



U.S. Department of Energy

**Office of River Protection**

P.O. Box 450  
Richland, Washington 99352

JUN 25 2003

0058825

0059825

03-ED-101

Mr. Michael A. Wilson, Program Manager  
Nuclear Waste Program  
State of Washington  
Department of Ecology  
1315 W. Fourth Avenue  
Kennewick, Washington 99336

**RECEIVED**  
JUL 14 2003  
**EDMC**

Dear Mr. Wilson:

**SUBMITTAL OF PREVENTION OF SIGNIFICANT DETERIORATION (PSD)  
APPLICATION FOR THE HANFORD TANK WASTE TREATMENT AND  
IMMOBILIZATION PLANT (WTP)**

Attached please find the PSD Application for the Hanford Tank WTP (DOE/ORP-2001-33, Revision 1). Rich Hibbard, the lead PSD permit writer for the State of Washington Department of Ecology, is being sent copies of the application with this transmittal. We have also copied other stakeholders, including Federal Land Managers, with this transmittal.

The PSD Permit is being revised to reflect design changes associated with the WTP. The design changes addressed in 24590-WTP-RPT-ENV-01-007, Revision 1, include:

- Increasing the number of High-Level Waste melters from one melter to two;
- Reducing the number of Low-Activity Waste melters from three to two;
- Changing the number and size of the steam boilers and eliminating hot water boilers; and
- Changing the fuel used in the boilers and diesel generators from low sulfur fuel to ultra-low sulfur fuel.

Based on the estimated potential emissions, the only criteria pollutants that have the potential to be emitted at levels exceeding those specified as significant in the PSD regulation are nitrogen oxides and particulate matter. Other criteria pollutants are estimated to be below the regulatory threshold that would require a more detailed review of their impact on air quality. This application presents the proposed best available control technology to reduce nitrogen oxide and particulate matter emissions.

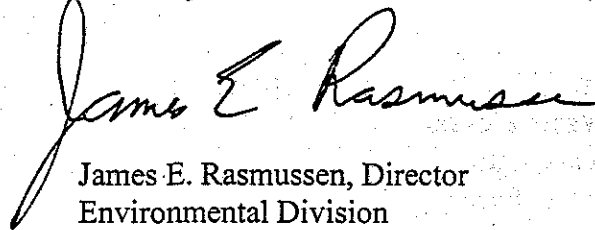
Mr. Michael A. Wilson  
03-ED-101

-2-

JUN 25 2003

If you have any questions, please contact me, or your staff may contact Dennis W. Bowser,  
Environmental Division, (509) 373-2566.

Sincerely,



James E. Rasmussen, Director  
Environmental Division

ED:DWB

Attachment

cc w/attach:

B. G. Erlandson, BNI  
J. Cox, CTUIR  
D. Sehgal, CTWSR  
C. Bowman, Ecology  
J. L. Hensley, Ecology (2 copies)  
R. Hibbard, Ecology (2 copies)  
O. S. Wang, Ecology  
D. Meyer, EPA  
W. E. Green, FHI  
S. Landino, NMFS  
D. Morse, NPS  
J. Notar, NPS  
E. Waddell, NPS  
P. Sobotta, NPT  
M. F. Jarvis, RL  
B. Bachman, USFS  
S. Martin, USFWS  
R. Jim, YN  
R. Lee, YN

Administrative Record  
Environmental Portal, LMSI

cc w/o attach:

B. Curn, BNI  
R. J. Henschel, BNI  
P. Peistrup, BNI  
J. Su-Coker, BNI  
E. S. Aromi, CHG  
D. Carrell, CHG  
S. Dahl, Ecology  
J. J. Lyon, Ecology  
J. A. Bates, FHI  
J. L. Hanson, INNOV  
A. W. Conklin, WDOH

Attachment  
03-ED-101

Prevention of Significant Deterioration Application



Document title:

# Prevention of Significant Deterioration Application for Hanford Tank Waste Treatment and Immobilization Plant

Contract number: DE-AC27-01RV14136

Department: Environmental

Author(s): J Su-Coker

B Curn

*Bary Curn*

ISSUED BY  
FPP-WTP PDC  
DM 6/19/03  
INIT DATE

Principal author  
signature:

Document number: 24590-WTP-RPT-ENV-01-007, Rev 1

Checked by: B Erlandson

Checker signature:

*Brod Erlandson*

Date of issue: 19 June 2003

Issue status: Approved

Approved by: P Peistrup

Approver's position: Environmental Manager

Approver signature:

*Chris E. B...*

River Protection Project  
Waste Treatment Plant  
2435 Stevens Center Place  
Richland, WA 99352  
United States of America  
Tel: 509 371 2000

DOE/ORP-2001-33, Rev 1



## History Sheet

Rev	Date	Reason for revision	Revised by
A	02 Oct 2001	Draft for Review	J Su-Coker
0	18 Dec 2001	Approved	J Su-Coker
1	19 June 2003	Approved	J Su-Coker

## Contents

---

Acronyms .....	iv
Executive Summary .....	viii
1 Introduction .....	1-i
2 Process Description .....	2-i
3 Emission Estimates and Applicable PSD Analyses .....	3-i
4 Best Available Control Technology (BACT) Analysis NO <sub>x</sub> .....	4-i
5 Best Available Control Technology (BACT) Analysis PM .....	5-i
6 Air Quality Impact Analysis .....	6-i
7 References .....	7-i

## Appendices

---

Appendix A - State Environmental Policy Act Environmental Checklist for the River Protection Project - Waste Treatment Plant (24590-WTP-RPT-ENV-01-011, Rev 2) ....	A-i
Appendix B - Calculation Sheet: Emission Estimate for Revision 1, Prevention of Significant Deterioration Permit Application (24590-WTP-HAC-50-00006, Rev A) .....	B-i
Appendix C - Treatment Technology Cost Analysis .....	C-i
Appendix D - Air Quality Monitoring Data .....	D-i

## Acronyms

$\mu\text{g}/\text{m}^3$	micrograms per cubic meter
AAS	air atomized scrubber
AES	atomic emission spectroscopy
acfm	actual cubic feet per minute
A-DPF	active diesel particulate filters
AHL	analytical hot cell laboratory
ALARA	as low as reasonably achievable
ASILs	acceptable source impact levels
BACT	best available control technology
BARCT	best available radionuclide control technology
bhp	brake-horse power
BOF	balance of facilities
BOOS	burners out of service
BPIP	building profile input program
CAA	<i>Clean Air Act</i>
CARB	California Air Resources Board
CCVF	crankcase vent filtration
CFR	Code of Federal Regulations
$\text{ClO}_2$	chlorine dioxide
CO	<i>carbon monoxide</i>
$\text{CO}_2$	carbon dioxide
COHPAC	compact hybrid particulate collector
CONAGT	Committee on Nuclear Air and Gas Treatment
CXP	cesium ion exchange process
DOC	diesel oxidation catalyst
DOE	US Department of Energy
DOE-RL	US Department of Energy - Richland Operations Office
DPF	diesel particulate filter
DST	double-shell tank
Ecology	Washington State Department of Ecology
EDTA	ethylene diamine tetra-acetic acid

EPA	US Environmental Protection Agency
EPRI	Electrical Power Research Institute
ESP	electrostatic precipitator
EVS	ejector venturi scrubber
FGR	flue gas recirculation
FLM	federal land manager
FR	<i>Federal Register</i>
FT-IR	fourier transformation infrared spectrometry
GIS	geographical information system
H <sub>2</sub> O	water
H <sub>2</sub> O <sub>2</sub>	hydrogen peroxide
H <sub>2</sub> S	hydrogen sulfide
HC	hydrocarbon
HEME	high efficiency mist eliminator
HEMF	high-efficiency metal filter
HEPA	high efficiency particulate air
HLP	high-level waste lag storage and blending process
HLW	high level waste
HNO <sub>3</sub>	nitric acid
HSS	hydrosonic scrubber
IHLW	immobilized high-level waste
ILAW	immobilized low-activity waste
ISC3	<i>Industrial Source Complex Model, version 3</i>
ISCST3	<i>Industrial Source Complex Short Term Air Dispersion Model, version 00101</i>
KW	kilowatt
LAER	lowest achievable emission rate
LAW	low-activity waste
lb/hr	pounds per hour
LEA	low excess air
LIGO	Laser Interferometer Gravitational Wave Observatory
LNB	low-NO <sub>x</sub> burner
LR	load reduction
M	molar

**24590-WTP-RPT-ENV-01-007, Rev 1**  
**Prevention of Significant Deterioration Application for**  
**Hanford Tank Waste Treatment and Immobilization Plant**

MACT	maximally achievable control technology
mmBtu	million British thermal unit
MnO <sub>2</sub>	manganese dioxide
MnO <sub>4</sub> <sup>-</sup>	permanganate
MnO <sub>4</sub> <sup>-2</sup>	manganate ions
Mrad	mega roentgen adsorbed dose
MW	megawatt
NAAQS	national ambient air quality standard
NCR	nonselective catalytic reduction
NH <sub>3</sub>	ammonia
Nm <sup>3</sup> /hour	normal cubic meters per hour
NO	nitrogen oxide
NO <sub>2</sub>	nitrogen dioxide
NO <sub>2</sub> <sup>-</sup>	nitrite
NO <sub>3</sub> <sup>-</sup>	nitrate
NOC	notice of construction
NO <sub>x</sub>	nitrogen oxides
NSR	new source review
NWS	National Weather Service
O <sub>2</sub>	oxygen
O <sub>3</sub>	ozone
O/W EF	oil/water emulsified fuel
P-DPF	passive diesel particulate filters
PJM	pulse jet mixer
PM	particulate matter
PM <sub>2.5</sub>	fine particulate matter
PM <sub>10</sub>	particulate matter less than 10 microns
ppm	parts per million
ppmv	parts per million by volume
PSD	prevention of significant deterioration
psig	pounds per square inch
PUREX	plutonium uranium extraction plant
RACT	reasonably available control technology

RAP	reduced air preheat
RCRA	<i>Resource Conservation and Recovery Act</i>
RFD	reverse flow diverters
SAS	steam atomized scrubber
SBS	submerged bed scrubber
SC	staged combustion
scfm	standard cubic feet per minute
SCONO <sub>x</sub>	SCONO <sub>x</sub> catalytic reduction
SCR	selective catalytic reduction
sft <sup>3</sup> /sec	standard cubic feet per second
SNCR	selective noncatalytic reduction
SOF	soluble organic fraction
SIC	standard industrial classification
SO <sub>2</sub>	sulfur dioxide
SO <sub>x</sub>	sulfur oxides
T-BACT	best available control technology for new sources of toxic air pollutants
TCO	thermal catalytic oxidizer
TCLP	toxicity characteristic leaching procedure
TLP	treated low-activity waste evaporation process
TRU	transuranic
UFP	ultrafiltration process
ULPA	ultra-low penetration air
VLSI	very large-scale integration
VOC	volatile organic compounds
WAC	<i>Washington Administrative Code</i>
WDOH	State of Washington Department of Health
WESP	wet electrostatic precipitator
WTP	Hanford Tank Waste Treatment and Immobilization Plant
XRD	x-ray diffraction
XRF	x-ray spectrometry

## Executive Summary

An analysis of the potential criteria pollutant emissions from the Hanford Tank Waste Treatment and Immobilization Plant (WTP) has been made to satisfy prevention of significant deterioration (PSD) regulations under the *Clean Air Act* (CAA), as administered by the Washington Department of Ecology (Ecology) under Washington Administrative Code (WAC) 173-400-141) and the US Environmental Protection Agency (EPA) under 40 Code of Federal Regulations (CFR) 52.21.

The WTP will be located in an area that is in attainment of national ambient air quality standards (NAAQSs). The maximum potential emissions have been estimated using the best available information on the process and offgas treatment systems, the necessary operating equipment, operational schedules, and plans, the necessary facility support activities, and equipment. Based on anticipated maximum potential emission (see section 3), it was determined that nitrogen oxides (NO<sub>x</sub>) and particulate matter (PM) have the potential to be emitted at levels exceeding those specified as significant under PSD regulations. Other criteria pollutants are estimated to be below the regulatory threshold that would require a more detailed review of their impact on air quality.

The purpose of this application is to present the following:

- The proposed best available control technology (BACT) to reduce NO<sub>x</sub> and PM emissions from the WTP (see sections 4 and 5)
- Results of air quality impacts (see section 6)
- Results of additional environmental impacts (see section 6)
- Results of air quality impact to Class I areas within a 100-mile distance (see section 6)

In effect, the BACT is an emission limitation. It includes the commitment to use operational practices and techniques, as well as the appropriate pollution control equipment to minimize the impact of criteria pollutants on human health and the environment when project emissions exceed established criteria pollutant thresholds. The BACT has been used to limit emissions from the potential sources of NO<sub>x</sub> and PM originating from the WTP.

The proposed BACT for the potential sources of NO<sub>x</sub> emissions are summarized in the following table.

**Summary of Proposed BACT for NO<sub>x</sub> Emission Sources**

Source	Proposed BACT	Control Efficiency
Pretreatment (see section 4.2)	Operating practices	Not applicable
Low-activity waste (LAW) melter offgas (see section 4.3)	Selective catalytic reduction (SCR)	Greater than or equal to 95 %
High-level waste (HLW) melter offgas (see section 4.4)	SCR	Greater than or equal to 95 %

**24590-WTP-RPT-ENV-01-007, Rev 1**  
**Prevention of Significant Deterioration Application for**  
**Hanford Tank Waste Treatment and Immobilization Plant**

Source	Proposed BACT	Control Efficiency
Boilers (see section 4.5)	Low NO <sub>x</sub> burners, steam atomization, limited operating hours	Greater than 70 %
Generators (see section 4.6)	Good combustion engineering practices, limited operating hours	Not applicable

An air quality analysis has been performed to demonstrate that new emissions from a proposed new WTP will not cause or contribute to a violation of any applicable NAAQS. For the purpose of determining compliance with the ambient standards, NO<sub>x</sub> emissions were modeled as nitrogen dioxide (NO<sub>2</sub>). The standards for NO<sub>2</sub> are itemized in the following table.

**Summary of Ambient Air Quality Standards for Nitrogen Dioxide (NO<sub>2</sub>)**

Air Quality Standard	Ambient NO <sub>2</sub> Concentration (micrograms per cubic meter) (µg/m <sup>3</sup> )
NAAQS	100
PSD increment	25
Significant monitoring concentration	14
Significance level for air quality impacts in Class II areas requiring a full impact analysis	1
Significance level for air quality impact on a Class I area for a proposed source within 100 kilometers (km) of a Class I area	1

Reference: 40 CFR 52.21 and *New Source Review Workshop Manual* (EPA 1990a)

Section 6 of this application provides a discussion of these various NO<sub>x</sub>/NO<sub>2</sub> concentration levels, their relevance to the proposed project, and additional regulatory references. Results of the air quality impact analysis have indicated no significant impact. The maximum near-field ambient air concentration of NO<sub>2</sub> is 0.61 µg/m<sup>3</sup>. The maximum far-field ambient air concentration of NO<sub>2</sub> corresponds to a concentration increase of less than 0.00505 µg/m<sup>3</sup>. These levels are below the most stringent levels set by EPA in order to prevent damage to Class I national park and wilderness areas.

The proposed BACT for the potential sources of PM emissions is summarized in the following table.

**Summary of Proposed BACT for PM Emission Sources**

Source	Proposed BACT	Control Efficiency
Pretreatment (see section 5.2)	Single-stage HEPA filtration – C2 and C3 area emission units	99.95 %
	Two-stage HEPA filtration – C5 area emission units	99.9995 %
LAW (see section 5.2)	Single-stage HEPA filtration – C2 and C3 area emission units	99.95 %
	Two-stage HEPA filtration – C5 area emission units	99.9995 %



**24590-WTP-RPT-ENV-01-007, Rev 1**  
**Prevention of Significant Deterioration Application for**  
**Hanford Tank Waste Treatment and Immobilization Plant**

Source	Proposed BACT	Control Efficiency
HLW (see section 5.2)	Single-stage HEPA filtration – C2 and C3 area emission units	99.95 %
	Two-stage HEPA filtration – C5 area emission units	99.9995 %
Laboratory (see section 5.2)	Single-stage HEPA filtration – C2 and C3 area emission units	99.95 %
	Two-stage HEPA filtration – C5 area emission units	99.9995 %
Boilers (see section 5.3)	Good combustion engineering practices, a particulate emission limit of 0.020 lb/mmBtu	Not applicable
Generators (see section 5.4.1)	Good combustion engineering practices, limited testing hours	Not applicable
Glass former facility (GFF) (see section 5.4.2)	Baghouse	99.9 %

The air quality analysis also demonstrates that new emissions from a proposed new WTP will not cause or contribute to a violation of any applicable NAAQS or PSD increment for PM<sub>10</sub>. The standards for PM<sub>10</sub> are itemized in the following table.

Air Quality Standard	Ambient PM <sub>10</sub> Concentration µg/m <sup>3</sup>	
	24-hour average	annual average
NAAQS	150	50
Significance level for air quality impacts in Class II areas requiring a full impact analysis	5	1
PSD increment	25	
Significant monitoring concentration	5	
Significance level for air quality impact on a Class I area for a proposed source within 100 kilometers (km) of a Class I area	1	

Reference: 40 CFR 52.21 and *New Source Review Workshop Manual* (EPA 1990a)

Section 6 of this application provides a discussion of these various PM<sub>10</sub> concentration levels, their relevance to the proposed project, and additional regulatory references. The maximum near-field ambient air concentration for PM<sub>10</sub> was determined to be 0.11 µg/m<sup>3</sup> on an annual basis and 1.93 µg/m<sup>3</sup> on a 24-hour average basis. These results indicate that there is no significant impact. The maximum far-field ambient air concentration of PM<sub>10</sub> corresponds to a concentration increase of less than 0.00080 µg/m<sup>3</sup> on an annual basis and 0.058 µg/m<sup>3</sup> on a 24-hour average basis. These levels are below the most stringent levels set by EPA in order to prevent damage to Class I national park and wilderness areas.

## Contents

---

<b>1</b>	<b>Introduction .....</b>	<b>1-1</b>
1.1	Purpose.....	1-1
1.2	Facility Identification and Background.....	1-1
1.2.1	Responsible Parties .....	1-1
1.2.2	Facility Location .....	1-2
1.3	Applicable PSD Regulations.....	1-2
1.3.1	Goal of the PSD Permitting Program.....	1-2
1.3.2	PSD Permitting Requirements .....	1-3
1.4	Other <i>Clean Air Act</i> Regulations.....	1-4

## Tables

---

Table 1-1	Significant Net Emissions Increase Limits for PSD Pollutants.....	1-5
-----------	---	-----

## Figures

---

Figure 1-1	Location of the WTP on the Hanford Site.....	1-6
------------	--	-----

# 1 Introduction

This PSD application is presented to obtain PSD air permit approval for design changes associated with the WTP, which will be located at the US Department of Energy (DOE) Hanford Site near Richland, Washington, as shown in Figure 1-1. The original PSD application was approved by Ecology on 8 July 2002, which allowed the start of construction of the WTP with the previous design consisting of 3 LAW facility melters and 1 HLW facility melter (3 + 1 melter configuration). This application revision is requesting Ecology's approval on a redesigned WTP that includes 2 LAW melters and 2 HLW melters (2 + 2 configuration).

The WTP is being designed to have a lifespan of approximately 40 years. The WTP will manage waste from the Hanford Site double-shell tank (DST) system that will be immobilized in the form of a glass matrix contained in stainless steel containers using 2 HLW melters and 2 LAW melters, with space for a third LAW melter. The annual throughput for LAW and HLW melters is 2010 US tons per year and 2410 US tons per year, respectively. The throughput values are based on an average daily throughput of 55 US tons per day and 6.6 US tons per day operating at 365 days per year.

This PSD application is prepared in accordance with the requirements cited in WAC 173-400-141, *General Regulations for Air Pollution Sources*, and 40 CFR 52.21, *Prevention of Significant Deterioration of Air Quality*, for control of potential criteria pollutant emissions. The following sections provide the purpose, location, and construction schedule of the WTP. This section also provides a summary of applicable PSD regulations.

## 1.1 Purpose

The federal CAA requires new major stationary sources of air pollution, and major modifications to major stationary sources, to obtain an air quality permit before starting construction. This PSD application provides the following items, which are required for areas that are unclassified or in attainment of the NAAQS:

- Results of BACT analysis
- Results of the ambient air quality analysis
- Results of the impact to soils, vegetation, and visibility
- Demonstration of the air quality impact to Class I areas within a 100-mile distance

## 1.2 Facility Identification and Background

### 1.2.1 Responsible Parties

DOE-Richland (DOE-RL) plans to use 120 acres (48 hectares) for the construction and operation of the WTP.

The responsible manager for the WTP is shown below.

Owner/Operator: Roy J. Schepens, Manager  
US Department of Energy, Office of River Protection  
Post Office Box 450  
Richland, Washington 99352  
Phone: 509-376-6677

### **1.2.2 Facility Location**

The proposed WTP will be built at the eastern end of the 200 East Area of the Hanford Site, near the former grout treatment facility, the 241-AP tank farm complex, and the plutonium uranium extraction plant (PUREX). The WTP will be located near the center of the Hanford Site, which covers approximately 1,450 square kilometers (560 square miles) of semi-arid land in southeastern Washington. The site is located northwest of Richland, Washington.

The WTP will be sited at Gable Butte, Washington (shown on a 7.5-minute quadrangle topographic map in Section 3, T12N, R26E) located at the Willamette Base and Meridian. A site map is presented in Figure 1-1.

### **1.3 Applicable PSD Regulations**

The federal CAA requires new major stationary sources of air pollution and major modifications to major stationary sources to obtain an air quality permit before starting construction. The process of permitting major sources is called new source review (NSR) under PSD. Air quality permits for major sources in non-attainment areas are referred to as non-attainment area permits. Since the WTP will be located in an attainment area for regulated pollutants, non-attainment permitting is not required for the construction of the WTP. The NSR requirements under PSD apply to the WTP for emissions of  $\text{NO}_x$  and PM because these criteria pollutants have the potential to be emitted at levels exceeding those specified as significant under the PSD regulations (see Table 1-1 for limits). For the purposes of this application, all PM generated by the proposed facility is assumed to be  $\text{PM}_{10}$ .  $\text{NO}_x$  is estimated to have a maximum potential to be emitted at a rate greater than its significant emission rate of 40 US tons per year for  $\text{NO}_x$ .  $\text{PM}_{10}$  is estimated to have a maximum potential to be emitted at a rate greater than its significant emission rate of 15 US tons per year.

#### **1.3.1 Goal of the PSD Permitting Program**

The basic goals of the PSD requirements are as follows:

- To ensure that industrial and commercial growth occur without damaging air quality
- To protect public health and welfare from any adverse effects that might occur even at air quality levels better than those specified in NAAQS
- To preserve, protect, and enhance the air quality in areas of special value, such as national parks and wilderness areas

PSD requirements are pollutant-specific. Although a facility may emit several air pollutants, only a few or even 1 pollutant may be subject to PSD permit requirements, depending on the facility's potential for emitting each pollutant.

Federal PSD requirements are codified at 2 locations. The PSD regulations under 40 CFR 51.166, *Requirements for Preparation, Adoption, and Submittal of Implementation Plan*, specify the minimum requirements that a state PSD permit program must contain in order to obtain approval by the EPA as a revision to a state implementation plan. The regulations in 40 CFR 52.21 delineate the federal PSD program requirements that are applied as part of the state implementation plan for states that have not submitted a PSD program meeting the requirements of 40 CFR 51.166. The requirements of Sections 160 through 165 of the CAA are not met, since the Ecology plan does not include approvable procedures for preventing the significant deterioration of air quality. The provisions of 40 CFR 52.21 (b) through (w) have therefore been incorporated and made part of the applicable plan for the state of Washington. The state of Washington has amended WAC 173-400 (and WAC 173-401) to update pre-construction permitting programs for consistency with federal rules effective 13 August 2001.

### **1.3.2 PSD Permitting Requirements**

The predominant requirement of PSD regulations stipulates that new major stationary sources and major modifications be reviewed for compliance with PSD requirements, and that a PSD permit be issued for the source or modification prior to their construction. For a PSD permit to be issued, an applicant must perform the following:

- Conduct a facility-specific BACT analysis that determines the maximum degree of pollutant reduction achievable for the proposed source or modification and that considers energy, environmental, and economic impacts.
- Conduct an ambient air quality analysis. Each PSD source or modification applicant must perform an air quality analysis to demonstrate that the new pollutant emissions will not violate either an applicable NAAQS or an applicable PSD increment.
- Analyze impacts to soils, vegetation, and visibility. An applicant is required to analyze whether new pollutant emissions will impair visibility or adversely affect soils or vegetation. This analysis must include potential direct effects of emissions and indirect impacts from general commercial, residential, industrial, and other growth associated with the proposed source or modification.
- Ensure that new sources or modifications will not adversely impact a Class I area. If the federal land manager determines that emissions from a proposed source or modification will impair air quality-related values in a Class I area, the federal land manager may recommend that a PSD permit be denied.
- Before final action on a PSD application can be taken, perform adequate public participation functions as specified by the permitting authority. Perform specific public notice requirements and hold a public comment period as required.

A major stationary source under PSD regulations is any source that is included in a list of 28 source categories and emits, or has the potential to emit, 100 US tons per year or more of any PSD pollutant, or any other source type that has the potential to emit 250 US tons per year or more of any PSD pollutant. A stationary source includes pollutant-emitting activities that belong to the same industrial grouping, are located on contiguous or adjacent properties, and are under common control. A major modification is a physical change or change in operation of a major source that would result in a significant net emissions increase of any PSD pollutant. Significant pollutant emission rates are defined by the PSD regulations as shown in Table 1-1.

In addition, a major modification includes any pollutant emission rate within 10 kilometers of a Class I area that causes a significant air quality impact in a Class I area. The WTP represents a modification to the Hanford 200 Area DOE site. The Hanford DOE site is under the Standard Industrial Classification

(SIC) Code 4953 for refuse systems. It is a federal cleanup site, and is categorized as a major source under PSD because the overall facility was found to have the potential to emit more than 250 US tons per year of the pollutants  $\text{NO}_x$  and  $\text{PM}_{10}$ . Based on the maximum potential to emit emission rates presented in section 3 of this document, the addition of the WTP will result in significant pollutant emission increases in  $\text{NO}_x$  and  $\text{PM}_{10}$ . The amount of significant increases is defined as 40 US tons per year for  $\text{NO}_x$  and 15 US tons per year for  $\text{PM}_{10}$ . The maximum potential emissions from the proposed new facility will total more than the limiting amounts for both  $\text{NO}_x$  and  $\text{PM}_{10}$ . As a result, the addition of the WTP to the Hanford Site required a PSD permit prior to the initiation of its construction.

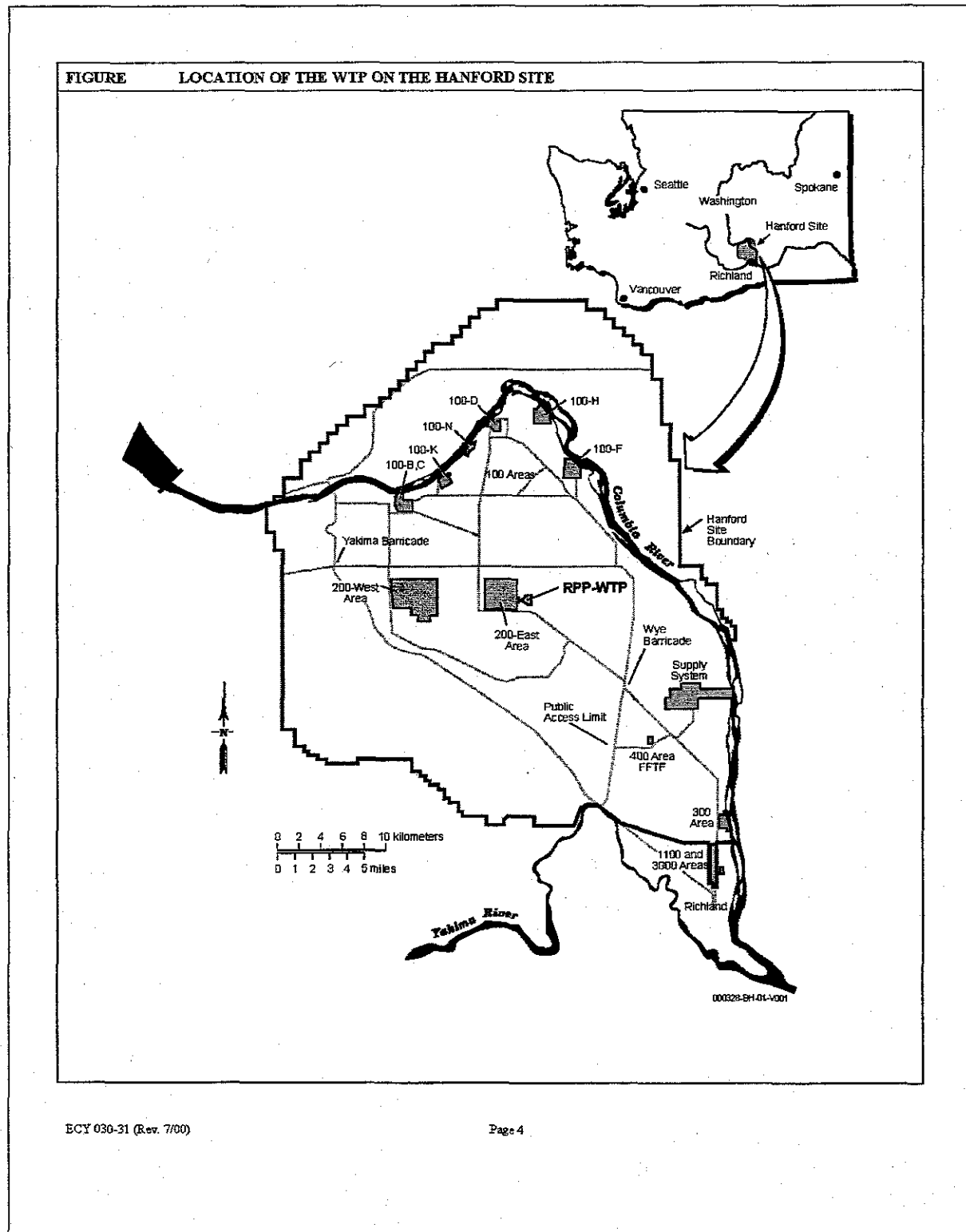
#### **1.4 Other Clean Air Act Regulations**

As a new facility, the WTP must also comply with the codified rules in WAC 173-400. Specifically, guidelines enumerated in WAC 173-400-110 WAC, NSR, and WAC 173-400-113 state that requirements for new sources in attainment or unclassifiable areas must be followed. These regulations are addressed in a separate notice of construction (NOC) permit application for non-radionuclide emissions. The WAC 173-400-113(2) requires that new sources must employ BACT for increases in criteria pollutant emissions. That application shall be submitted to Ecology and will also meet requirements stipulated in WAC 173-460, *Controls for New Sources of Toxic Air Pollutants*, and WAC 173-400-110. The WTP non-radionuclide NOC application, 24590-WTP-RPT-ENV-01-009, *Non-Radioactive Air Emission Notice of Construction Permit Application for The River Protection Project - Waste Treatment Plant*, contains a best available control technology analysis for criteria and toxic air pollutants (T-BACT), a process description, and an air quality impact analysis that compares dispersion modeling results of the toxic air pollutants to the Washington State acceptable source impact levels (ASILs). Finally, Chapter 173-401, WAC, *Operating Permit Regulation*, specifies the permitting requirements to be met for major sources, including the Hanford Site.

**Table 1-1 Significant Net Emissions Increase Limits for PSD Pollutants**

Defined in WAC-173-400-113 (1)(d)	US Tons per Year
Carbon monoxide (CO)	100
Nitrogen oxides (NO <sub>x</sub> )	40
Sulfur dioxide (SO <sub>2</sub> )	40
Particulate matter (PM)	25
Fine particulate matter (PM <sub>10</sub> )	15
Volatile organic compounds (VOC)	40
Lead	0.6
Fluorides	3
Sulfuric acid mist	7
Hydrogen sulfide (H <sub>2</sub> S)	10
Total reduced sulfur (including H <sub>2</sub> S)	10
Municipal waste combustor organics (as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	3.2 grams per year
Municipal waste combustor metals (measured as PM)	15
Municipal waste combustor acid gases (measured as sulfur dioxide and hydrogen chloride)	40
Municipal solid waste landfill (measured as non-methane organic compounds)	50
Ozone-depleting substances	100

Figure 1-1 Location of the WTP on the Hanford Site





## Contents

<b>2</b>	<b>Process Description .....</b>	<b>2-1</b>
2.1	Process Overview .....	2-1
2.2	Pretreatment Plant.....	2-1
2.2.1	Ultrafiltration Process System .....	2-2
2.2.2	HLW Lag Storage and Blending Process System.....	2-2
2.2.3	Cesium Ion Exchange Process System .....	2-2
2.2.4	Treated LAW Evaporation Process System.....	2-3
2.2.5	Pretreatment Offgas Emission Sources.....	2-4
2.2.6	Pretreatment Building Ventilation and Process Offgas Treatment Systems .....	2-4
2.3	LAW Vitrification .....	2-5
2.3.1	LAW Glass Former Feed System .....	2-5
2.3.2	LAW Melter Feed System .....	2-6
2.3.3	LAW Melters .....	2-6
2.3.4	Immobilized Glass Container Decontamination and Monitoring .....	2-8
2.3.5	LAW Building Ventilation and Process Offgas Emission Sources.....	2-8
2.3.6	LAW Building Ventilation and Process Offgas Treatment Systems .....	2-8
2.4	HLW Vitrification Plant.....	2-9
2.4.1	HLW Glass Former Feed System .....	2-9
2.4.2	HLW Melter Feed System .....	2-9
2.4.3	HLW Melter.....	2-10
2.4.4	Immobilized HLW Canister Decontamination and Monitoring.....	2-11
2.4.5	HLW Building Ventilation and Process Offgas Emission Sources.....	2-12
2.4.6	HLW Building Ventilation and Process Offgas Treatment Systems .....	2-12
2.5	Melter Offgas Maintenance Bypass Systems .....	2-13
2.6	Analytical Laboratory .....	2-13
2.6.1	Analytical Radiological Laboratory Equipment System.....	2-13
2.6.2	Analytical Hot Cell Laboratory Equipment System.....	2-14
2.6.3	Radioactive Solid Waste Management .....	2-14
2.6.4	Radioactive Liquid Waste Disposal .....	2-14
2.6.5	WTP Analytical Laboratory Offgas Emissions.....	2-14
2.7	WTP Building Ventilation Systems .....	2-15
2.8	Balance of Facilities.....	2-16
2.8.1	Diesel Generators.....	2-16
2.8.2	Fire Water Pumps .....	2-16
2.8.3	Steam Boilers.....	2-16
2.8.4	Glass Former Facility.....	2-17
2.8.5	Other Balance of Facilities.....	2-17

## Figures

Figure 2-1	WTP Process Overview .....	2-18
Figure 2-2	Pretreatment Plant Process Overview .....	2-19
Figure 2-3	Pretreatment Plant Process Overview .....	2-20

Figure 2-4	LAW Vitrification Plant Process Overview .....	2-21
Figure 2-5	HLW Vitrification Plant Process Overview .....	2-22
Figure 2-6	Pretreatment Building Ventilation Diagram.....	2-23
Figure 2-7	LAW Building Ventilation Diagram .....	2-24
Figure 2-8	HLW Building Ventilation Diagram .....	2-25
Figure 2-9	Laboratory Ventilation Diagram.....	2-26

## 2 Process Description

### 2.1 Process Overview

The WTP is being constructed to store and treat mixed waste from the Hanford Site DST system. The WTP will consist of 3 main processes: pretreatment, LAW vitrification, and HLW vitrification. A simplified WTP overall process flow diagram is shown in Figure 2-1. Tank waste will be received in the pretreatment facility, where it will be separated into low-activity waste (LAW) and high-level waste (HLW) feed. Waste will be immobilized in a glass matrix enclosed in steel containers. Offgas generated by the pretreatment and vitrification processes will be treated in independent offgas treatment systems. Typical offgas streams include process vessel ventilation, melter offgas, and exhaust from fluidic transfer devices, such as reverse flow diverters and pulse jet mixers. Simplified process overviews of the pretreatment and vitrification processes are depicted in Figure 2-2 through Figure 2-5.

Building ventilation systems will also be incorporated into each of the process plants (see Figure 2-6 through Figure 2-9) ventilating the C2, C3, and C5 areas. Section 2.7 provides a description of the ventilation systems. Air from the treated building air ventilation systems will also be vented to the atmosphere through dedicated flues.

The WTP will have an onsite analytical laboratory to support sampling and analysis activities. The offgases generated from sampling and analysis activities will be treated and vented to the atmosphere through dedicated flues. Support systems and utilities required for the WTP will be provided by the balance of facilities (BOF).

### 2.2 Pretreatment Plant

The pretreatment plant is designed to receive, separate, and prepare the LAW and HLW feeds for vitrification. Depending on the sodium content of the waste feed, low sodium concentration (less than 5 molar) waste will be concentrated in the waste feed evaporator.

When the sodium concentration is acceptable for further processing (either as received or after evaporation), the waste will go through the following systems:

- Ultrafiltration process (UFP) system
- HLW lag storage and blending process (HLP) system
- Cesium ion exchange process (CXP) system
- Treated LAW evaporation process (TLP) system

The evaporator offgas streams will be processed through condensers. The condensates will be collected and transferred to condensate tanks for discharge to the liquid effluent retention facility, or the effluent treatment facility, for subsequent treatment. The non-condensable gases will be routed to the pretreatment process vessel ventilation treatment system.

The ultrafiltration system will remove entrained solids from the concentrated waste feed. For certain waste feed, strontium and transuranic (TRU) compounds will be precipitated by adding reagents to the waste feed prior to ultrafiltration. The precipitate containing strontium and transuranic compounds will be concentrated and washed in the ultrafiltration system before incorporation into the HLW feed. The

liquid separated by ultrafiltration is the LAW feed, and the solid portion from the ultrafiltration is the HLW feed.

The LAW feed will pass through the cesium ion exchange system to separate the cesium from the LAW feed. The cesium concentrate will be blended with the solids from ultrafiltration prior to being transferred to the HLW vitrification plant. The eluant from the ion exchange systems will be further concentrated through the treated LAW evaporation process system. The operation of the treated LAW evaporator will be similar to that of the waste feed evaporator. The concentrated LAW feed will then be transferred to the LAW vitrification plant.

Sections 2.2.1 through 2.2.6 provide additional details of the pretreatment plant process systems.

### **2.2.1 Ultrafiltration Process System**

The ultrafiltration process system will separate the effluents from the evaporator system into a high-solids stream (referred to as the HLW feed stream) and a low-solids stream, the LAW feed stream.

Waste will be received into the ultrafiltration process system in batch modes. Depending on the waste feed, chemicals may be added to the waste mixture to complex the TRU elements and strontium. This will form solid particles that will then be separated into the HLW stream during the ultrafiltration process. Following the addition of the complexing chemicals, heat and agitation will be applied to ensure the TRU complexing process is completed.

The waste stream will then be fed to the ultrafilters, which are long bundles of permeable tubes. The liquids will pass through the permeable ultrafilter surface while the solids are retained. The low-solids stream is designated as the LAW feed stream, which will be further treated within the pretreatment plant prior to treatment through the LAW vitrification systems. The concentrated solids stream is designated as HLW feed, which will be stored at the pretreatment plant and blended with other HLW feed streams. This mixture will ultimately be processed through the HLW vitrification systems.

During waste processing, the permeability of the ultrafilters will diminish over time, and the filters will become clogged and require cleaning. Cleaning of the ultrafilter trains can be accomplished by using one of several different methods, including back-flushing with filter permeate, water, nitric acid, or caustic. Filter performance will be monitored to determine when cleaning is required.

### **2.2.2 HLW Lag Storage and Blending Process System**

The HLW lag storage and blending process system receives the HLW feed stream from the ultrafiltration process system. It provides lag storage for the high solids slurry and blends HLW vitrification feed prior to transfer and subsequent processing in the HLW vitrification plant. The system also provides for blending of cesium recovered from the LAW treatment process into the HLW feed stream prior to transfer to the HLW vitrification plant.

### **2.2.3 Cesium Ion Exchange Process System**

The primary function of the cesium ion exchange process system is to remove cesium from the LAW feed stream. This will be accomplished using a series of ion exchange columns containing a resin that preferentially extracts cesium. Elution of the cesium-loaded resin will be accomplished using dilute nitric acid. The cesium-loaded nitric acid will then be routed to the nitric acid recovery system, where the eluant is recovered for reuse and the cesium is concentrated for processing in the HLW vitrification plant.

The cesium ion exchange system uses 4 ion exchange columns to remove cesium from LAW. Three of the columns (a lead, a lag, and a polish column) will operate in the loading cycle in series. The fourth column will operate in parallel to the other columns, and will be eluted and regenerated, or have its spent ion exchange resin replaced. The column feeds will be rotated so that the following will be performed:

- The lead column is taken offline for elution/regeneration/media replacement
- The lag column becomes the lead column
- The polish column becomes the lag column
- The eluted/regenerated/media-replaced column becomes the polish column

The polishing column will be used in the loading cycle to ensure removal of cesium to the level required.

The concentration of cesium in the treated LAW will be monitored. Loading operation will be switched to the next position when the cesium concentration in the effluent of the lead column reaches a predetermined breakthrough point, or if significant amounts of cesium are detected in the effluent of the lag column or in the effluent of the polishing column.

After a number of loading and regeneration cycles, the ion exchange column resin is expected to lose performance, and is termed "spent". The number of cycles incurred before the column resin is spent depends on LAW feed constituents, operating temperatures, properties of the resin, radiation exposure, and LAW feed throughput rates. The spent resin will be slurried with a recycled resin flush solution, and flushed out of the column for resin disposal. A slurry of fresh resin will then be added to the column as a bed replacement.

#### **2.2.3.1 Cesium Nitric Acid Recovery Process System**

The cesium nitric acid recovery process system will recover nitric acid that was previously used for cesium ion exchange resin bed regeneration. In addition, this system will concentrate and transfer the cesium extracted from the ion exchange system for incorporation into the HLW melter feed.

During the process of regenerating the cesium ion exchange resin beds, eluate composed of cesium-bearing nitric acid will be fed to the nitric acid recovery evaporator operating under reduced pressure. This reduced pressure, maintained by steam ejectors, will lower the temperature to minimize corrosion. A closed-loop circulation stream will be fed from the evaporator to the steam-heated reboiler, and back to the evaporator. This heat input is the motive force for the evaporative process. The cesium concentrated in the evaporator will be routed to a concentrate storage tank for blending and incorporation into the HLW melter feed stream.

The cesium nitric acid recovery process system will only operate when a cesium ion exchange column is in the process of having its resin bed regenerated through an elution process. When elution of a cesium ion exchange column is not taking place, the nitric acid recovery system will be maintained in a standby mode.

#### **2.2.4 Treated LAW Evaporation Process System**

The treated LAW evaporation process system is designed to further concentrate the treated LAW feed from the cesium ion exchange process system. This system will also process purge liquid from the submerged bed scrubbers (SBSs).

The treated LAW evaporator will be a forced-circulation unit operating under a vacuum to reduce the operating temperature. The treated LAW from the cesium ion exchange process system will be transferred to the treated LAW evaporation process system. Submerged bed scrubber purge liquor from LAW vitrification will be received and neutralized prior to evaporation.

The 2 feeds to the treated LAW evaporator separator will be pumped continuously to the suction side of the recirculation pump. The recirculation pump will maintain a high flow rate around the evaporation system. The recirculation pump will transfer the waste through the reboiler and back into the treated LAW evaporator separator. The re-circulating waste stream is prevented from boiling in the reboiler tubes by maintaining a sufficient hydrostatic head that increases the boiling point above the temperature of the liquor in the reboiler.

As the liquid travels through the reboiler, the hydrostatic head will diminish and flash evaporation will occur as the flow enters the treated LAW evaporator separator. The liquid will continue to flash to equilibrium, and the vapor and liquid streams will be separated. The liquid stream will circulate in this closed loop (becoming more concentrated), while the vapor stream passes to the evaporator offgas system.

The concentrated waste stream will be pumped continuously out of the evaporator system. The concentrate off-take will be situated on the suction line of the re-circulation pump. The concentrated waste stream will be stored and processed through the LAW vitrification plant.

### **2.2.5 Pretreatment Offgas Emission Sources**

The emission sources from pretreatment processes are plant building air ventilation, process vessel vents, reverse flow diverter (RFD) offgas, and pulse jet mixer (PJM) offgas. The plant building air is expected to contain particulates. The offgases from process vessels, RFD, and PJM will contain particulates, volatile organics, semi-volatile organics, and acid gases.

Insignificant amounts of NO<sub>x</sub> gases are expected from radiolytic decomposition of nitric acid from the cesium nitric acid recovery process vessels (see process description in section 2.2.3.1). A discussion of the radiolytic NO<sub>x</sub> generation rate is included in Section 4.2. Descriptions of NO<sub>x</sub> emissions and proposed controls for the pretreatment plant are provided in sections 3 and 4 of this document.

Insignificant amounts of particulates are expected to be present in the building ventilation systems (less than 0.1 US ton. The building ventilation systems are described in section 2.7. Particulate emissions from the pretreatment processes are produced from the entrained solids in the fluidic device exhausts and the process vessel vents. Descriptions of the particulate emissions and proposed controls for the pretreatment plant are provided in sections 3 and 5 of this document.

The particulate emissions and NO<sub>x</sub> calculations for the pretreatment processes described in sections 2.2.1 through 2.2.4 are provided in Appendix B of this application.

### **2.2.6 Pretreatment Building Ventilation and Process Offgas Treatment Systems**

The particulate emissions from the pretreatment building ventilation systems will be treated through high-efficiency particulate air (HEPA) filters.

The pretreatment offgas from fluidic devices such as the RFD/PJMs will be treated through a mist eliminator and HEPA filters, and routed to the pretreatment plant stack, where it will be monitored and vented to the atmosphere.

The pretreatment offgas from vessels will be treated through the following components operating in a series:

- Caustic scrubber
- HEME
- HEPA filter
- Thermal oxidizer
- Carbon adsorber

Particulates will be removed through the HEPA filters. The NO<sub>x</sub> emissions will be removed through the caustic scrubber. The scrubber will remove radioactive aerosols, acid gases, and NO<sub>x</sub> emissions. The caustic scrubber will be a column with a bed filled with packing material. Sodium hydroxide solution flows down through the bed, while the offgas enters the bottom, and is drawn up through packing and caustic solution. Contact between the gas and the liquid in the bed causes a portion of the NO<sub>x</sub> in the vent gas to dissolve and form sodium nitrate. The scrubbing liquor collects in the sump of the column as well as any excess overflows to the pretreatment effluent collection.

## **2.3 LAW Vitrification**

The function of this system is to convert blended waste slurry and glass formers into molten glass. The LAW melter system design is based on operating 2 joule-heated ceramic melters and associated systems. Sections 2.3.1 through 2.3.6 describe the LAW vitrification processes.

### **2.3.1 LAW Glass Former Feed System**

Treated LAW feed will be analyzed to determine the glass additive formulation required for the conversion of the waste to glass. The glass additives specified in the formulation will be weighed and mixed with the treated LAW waste.

The glass former feed hoppers will receive blended glass formers and sucrose by dense-phase pneumatic conveyance from the glass-former handling facility. Each feed hopper will be equipped with a pneumatic blending head at the base of the hopper to re-blend the glass former feed.

The feed hoppers will be equipped with filters to remove the dust from air used for pneumatic conveying and blending. It is anticipated that a series of single-filter cartridges will be mounted on the top of the hoppers. The filters will be cleaned by introducing compressed air through the cleaning nozzle to blow accumulated dust back into the hoppers.

The feed hoppers will be equipped with load cells to weigh the glass formers to confirm that all of the material in the upstream blending silo is conveyed to the feed hoppers, and to confirm that all of the glass formers are transferred out of the feed hoppers. After the re-blending cycle, the glass formers will be gravity-fed with a rotary feeder into the melter feed preparation vessels where the blended glass formers are mixed with the LAW waste.

### 2.3.2 LAW Melter Feed System

The LAW melter feed will be transferred to each melter at a constant rate with air displacement slurry pumps. The pumps will transfer the slurry from the feed vessel to the melter utilizing air as the motive force. The melter feed nozzles will be installed in the melter lid for introduction of slurry over the melt pool cold cap. Each feed nozzle will be individually supplied from a separate pump to reduce the likelihood of line plugging. The feed nozzles will be water-cooled to prevent drying the feed before it reaches the melter. Water flushes will be used to clear the feed lines as necessary.

The feed rate to the melter pool will be determined based on the average plenum temperature in the melter. The plenum temperatures will be controlled in the range of 572 °F to 1112 °F. The plenum thermocouples will be used to monitor plenum temperature and change the rate of feeding to the melter.

### 2.3.3 LAW Melters

Each LAW melter will have a single internal glass chamber with a rectangular surface area. The melters will be lined with refractory material designed to withstand corrosion by molten glass. The energy for the melt will be delivered by 3 sets of electrodes mounted on opposite walls of the glass pool. The glass will be discharged through either of 2 discharge chambers located within one of the long axis walls of the melter. The lid of the melter will be composed of a layer of refractory backed by a corrosion resistant metal plate and support structure. The lid will also support the components that will be submerged in the melt pool and suspended in the melter plenum. The melter will be encased in an integral shielding and secondary containment enclosure.

#### Melter Containment System

The refractory will be part of the melter containment and can be thought of as 2 separate sections. These sections will be the refractory in contact with the molten glass pool, and the refractory surrounding the gas space above the glass pool, which is commonly referred to as the plenum. The glass pool refractory, in conjunction with active cooling provided by a water jacket, will provide glass containment, thermal insulation, and electrical isolation. The plenum refractory will be primarily designed to resist thermal shock, resist corrosion by offgases, and resist corrosion by splashed feed and glass.

The melter shell will consist of the lid and base plate as well as the structure needed to support the lid and provide a gas barrier between the refractory and the enclosure. The melter shell will be designed to allow operation of the melter at a negative pressure with controlled air in-leakage. A small purge will be provided for the annular space between the cooling panels and the shell to reduce the deposition of materials. This purge will be driven by a melter vacuum and vented to the building ventilation system. The controlled purge air in-leakage to the spaces between the gas barrier and the refractory will reduce the deposition of corrosive materials carried by the offgas.

The LAW melters will operate under a cascaded ventilation system. The melter plenum will be maintained at a vacuum with offgas system blowers and controlled injection of air into the offgas line near the melter exhaust. This will ensure containment and will avoid pressurization.

The melter shell will also contain a set of drains located in the base-plate, one in the space between the shell and the enclosure and one between the shell and the glass pool refractory. The drains will prevent the backup of water in the event of a cooling water leak or the uncontrolled addition of water from other sources. Each drain will have a sealing mechanism to prevent the inward flow of air due to melter vacuum, and a leak detection system.



The LAW melter will be designed so that no additional shielding or contamination control will be required for normal operations. This will be accomplished by enclosing the melter assembly with welded steel plates. Shielding will be incorporated by increasing the cooling box bottom plate thickness. Access panels will be provided in the enclosure. When removed, these panels will allow access to the jack-bolts, electrodes, electrode thermocouples, and viewing cameras.

### **Joule Heating**

The heat for melter startup will be provided by temporarily installed radiant electric heaters mounted through the lid of the melter. These heaters will melt the starter charge of glass former material sufficiently to make it ionically conductive between the melter's joule-heating electrodes. When a conducting path is established, the melter will be heated in a controlled manner by passing more and more current between the electrodes through the glass (a process known as joule heating). When the melter reaches the operating temperature, the startup heaters will be removed and slurry feeding will start.

The joule heating system will contain the melter electrodes, melter electrode power supplies, melter glass pool thermocouples, and the melter electrode control system.

The electrode configuration for each LAW melter will consist of 3 pairs of plate electrodes mounted parallel to each other on the long axis of the melter. The electrodes will have forced-air cooled electrode extensions. The extensions will penetrate the side of the melter below the glass level to minimize the effects of thermal expansion and to minimize the potential for sulfate corrosion. Active cooling of the extensions and the use of a water-cooling jacket will prevent glass from migrating through the refractory package adjacent to the electrode extension penetrations. Power to the electrodes will be single-phase alternating current applied across opposing electrodes. The nominal glass melt pool temperature will be 950 °C to 1250 °C. This will be measured with thermocouples in thermowells submerged into the pool at various locations. The power to the electrodes will be regulated to maintain the temperature at the nominal value.

### **Glass Discharge System**

Each LAW melter will have 2 identical and independently operated glass discharge systems located adjacent to each other on a long side of the melter. The glass discharge systems will include the melter glass level detectors, canister glass level detection, riser, airlift lance, trough, and a heated discharge chamber.

The glass discharge from the melter will be initiated by injecting air or an inert gas at the bottom of the airlift riser. As the gas bubbles rise in the glass they will entrain glass in the riser to the inlet of the trough, where the air bubbles burst and the entrained glass flows into the trough. The glass will then flow by gravity down the trough to the pour tip and into the waste container. The rate of glass discharge will be controlled by adjusting the rate at which the air and gas mixture is injected into the bottom of the riser.

The starting and stopping of the glass discharge will be based on the level of glass in the melter. It is desired to maintain the glass level in the melt pool to within an approximate 1.5-inch band to reduce thermal stresses on the refractory. Glass discharge operations will be monitored using a camera system to observe the glass pour stream. The level in the waste container will also be monitored by infrared thermal imaging and gamma level detectors to prevent overfilling.

### **2.3.4 Immobilized Glass Container Decontamination and Monitoring**

After the immobilized LAW (ILAW) container has been cooled and sealed, it will be decontaminated using carbon dioxide (CO<sub>2</sub>) blasting. The containers will be decontaminated with CO<sub>2</sub> pellets. The CO<sub>2</sub> blasting gun will contain an exhaust recovery hood to recover the effluent from the cleaning operation. Debris produced during decontamination will be collected with a local HEPA filtration system. This gas stream will then be vented to the atmosphere through the LAW vitrification plant ventilation system.

The decontaminated glass containers will be swabbed and surveyed for loose surface contamination prior to transport to the ILAW container storage area. If contamination exceeds the target levels, the container will be reworked through CO<sub>2</sub> decontamination, or a fixative will be applied to the outer surface of the container prior to transport to the ILAW container storage area.

### **2.3.5 LAW Building Ventilation and Process Offgas Emission Sources**

The emission sources from the LAW vitrification processes are plant building air ventilation, process vessel vents, and LAW melter offgas. The plant building air is expected to contain particulates. The offgases from process vessels will contain particulates, volatile and semi-volatile organics, and acid gases. The LAW melter offgas will contain particulates, radioactive gases, volatile and semi-volatile organics, acid gases, and NO<sub>x</sub> gases at relatively high temperature and moisture content.

NO<sub>x</sub> emissions are expected from decomposition of metal nitrates and from nitrites in the melter feed. Descriptions on NO<sub>x</sub> emissions and proposed controls for the LAW vitrification plant are provided in sections 3 and 4 of this document.

Insignificant amounts of particulates are expected to be present in the building ventilation systems (less than 0.1 US ton per year). The building ventilation systems are described in section 2.7. Particulate emissions from the LAW vitrification processes are produced from the entrained particulates from the feed and the glass melt. Descriptions of the particulate emissions and proposed controls are provided in sections 3 and 5 of this document.

The particulate and NO<sub>x</sub> emissions calculations for the LAW processes described in sections 2.3.1 through 2.3.4 are provided in Appendix B.

### **2.3.6 LAW Building Ventilation and Process Offgas Treatment Systems**

The particulate emissions from the building ventilation systems will be treated through HEPA filters. The LAW melter offgas treatment system will consist of the following components.

- Film cooler
- SBS
- Wet electrostatic precipitator
- HEPA filter
- Carbon adsorber
- Thermal catalytic oxidation (TCO) unit
- SCR unit
- Caustic scrubber

The particulates and NO<sub>x</sub> emissions from LAW vitrification processes will be removed through the HEPA filters, a carbon adsorber, and the SCR unit, respectively. After treatment in the TCO, the offgas enters a chamber where an ammonia solution is injected through an atomized spray and allowed to mix with the offgas. Urea or ammonia is added so that the NO<sub>x</sub> reduction reactions can be carried out. The offgas is routed through the first set of NO<sub>x</sub> catalyst modules. After the first module, more ammonia is injected into the offgas stream to allow further conversion in the second set. The offgas then goes through the second catalyst module. Reduction of NO<sub>x</sub> is also an exothermic reaction; therefore, it significantly increases the offgas temperature. This hot offgas then enters the hot side of the heat recovery unit to heat the incoming offgas. The cooled offgas stream is then directed to the caustic scrubber for final cooling. Iodine and acid gas removal is accomplished in either the carbon adsorber or the caustic scrubber.

## **2.4 HLW Vitrification Plant**

The purpose of this system is to convert blended waste slurry and glass formers into molten glass. The HLW melter system design is based on operating 2 joule-heated ceramic melters and associated systems. Sections 2.4.1 through 2.4.6 describe the HLW vitrification processes.

### **2.4.1 HLW Glass Former Feed System**

Treated HLW feed will be analyzed to determine the glass additive formulation for the conversion of the waste to glass. The glass additives specified in the formulation will be weighed and mixed with the treated HLW waste.

The glass former feed hoppers will receive blended glass formers and sucrose by dense-phase pneumatic conveyance from the glass-former handling facility. Each feed hopper will be equipped with a pneumatic blending head at the base of the hopper to re-blend the glass former feed.

The feed hoppers will be equipped with filters to remove the dust from air used for pneumatic conveying and blending. It is anticipated that a series of single-filter cartridges will be mounted on the top of the hoppers. The filters will be cleaned by introducing compressed air through the cleaning nozzle to blow accumulated dust back into the hoppers.

The feed hoppers will be equipped with load cells to weigh the glass formers to confirm that all of the material in the upstream blending silo is conveyed to the feed hoppers, and to confirm that all of the glass formers are transferred out of the feed hoppers. After the re-blending cycle, the glass formers will be gravity-fed with a rotary feeder, and blended with the HLW waste feed.

### **2.4.2 HLW Melter Feed System**

The HLW melter feed will be transferred to each melter at a constant rate with air displacement slurry pumps. The pumps will transfer the slurry from the feed vessel to the melter utilizing air as the motive force. The melter feed nozzles will be installed in the melter lid for introduction of slurry over the melt pool cold cap. Each feed nozzle will be individually supplied from a separate pump to reduce the likelihood of a line plugging. The feed nozzles will be insulated with ceramics to prevent the feed from before it reaches the melter. Water flushes will be used to clear the feed lines as necessary.

The feed rate to the melter pool will be determined based on the average plenum temperature in the melter. The plenum temperatures will be controlled in the range of 572 °F to 1112 °F. The plenum

thermocouples will be used to monitor plenum temperature and to change the rate of feeding to the melter.

### **2.4.3 HLW Melter**

Each HLW melter will have a single internal glass chamber with a rectangular surface area. The melter will be lined with refractory material designed to withstand corrosion by molten glass. The energy for the melt will be delivered by 3 sets of electrodes mounted on opposite walls of the glass pool. The glass will be discharged through either of 2 discharge chambers located within one of the long axis walls of each of the melters. The steel casing for the melter area will be provided with water cooling to maintain a thermal gradient in the bricks for corrosion control, to prevent migration of glass through the bricks, and to reduce heat load to the process cell. The lid of the HLW melters will be sealed to the melter shell in order to provide gas containment. The lid will provide a support structure through which subcomponents can be mounted for submersion in the melt pool and suspension in the melter plenum. Penetrations, primarily on the lid, through the outer shell are sealed by appropriate fittings that allow remote removal and replacement. The HLW melters will be remotely operated and maintained.

#### **Melter Containment System**

The refractory will be part of the melter containment system and can be thought of as 2 separate sections. These sections will be the refractory in contact with the molten glass pool and the refractory surrounding the gas space above the glass pool, which is commonly referred to as the plenum. The glass pool refractory, in conjunction with active cooling provided by a water jacket, will provide glass containment, thermal insulation, and electrical isolation. The plenum refractory will be primarily designed to resist thermal shock, to resist corrosion by offgases, and to resist corrosion by splashed feed and glass.

The melter shell will consist of the lid and baseplate, as well as the structure needed to support the lid. The melter shell is designed to allow operation of the melter at a negative pressure with controlled air in-leakage from the melter cave. The controlled purge air in-leakage to the spaces between the gas barrier and the refractory reduces the deposition of corrosive materials carried by the offgas. Because the melter will not have a secondary enclosure, purge air or controlled air in-leakage will be introduced directly from the melter cave.

The HLW melters will be operated under a cascaded ventilation system. The melter plenum will be maintained at a vacuum with offgas system blowers and controlled injection of air into the offgas line near the melter exhaust. This will ensure containment and will avoid pressurization.

The melter shell will have a drain located in the base-plate between the shell and the glass pool refractory. The drain will prevent the backup of water in the event of a cooling water leak or the uncontrolled addition of water from other sources. The drain will have a sealing mechanism to prevent the inward flow of air due to melter vacuum, and a leak detection system.

#### **Melter Joule Heating System**

The heat for the HLW melter startup will be provided by temporarily installed radiant electric heaters mounted through the lid of the melter. These heaters will melt the starter charge of glass former material sufficiently to make it ionically conductive between the melter's joule-heating electrodes. When a conducting path is established, the melter will be heated in a controlled manner by passing more and more current between the electrodes through the glass. Slurry feeding will start when the melter reaches its operating temperature.

The joule-heating system will contain the melter electrodes, electrode power supplies, melter glass pool thermocouples, and the electrode control system.

The electrode configuration for each HLW melter will consist of 3 plate electrodes; 2 mounted on opposite sides of the melter and one on the bottom. The electrodes will be cooled by forced-air and will have forced-air cooled electrode extensions. The extensions will penetrate the side of the melter below the glass level to minimize the effects of thermal expansion and to minimize the potential for sulfate corrosion. Active cooling of the extensions and the use of a water-cooling jacket will prevent glass from migrating through the refractory package adjacent to the electrode extension penetrations. Power to the electrodes will be a single-phase alternating current applied across opposing electrodes. The nominal glass melt pool temperature will be between 1742 °F to 2282 °F. This will be measured with thermocouples in thermowells submerged into the pool at various locations. The power to the electrodes will be regulated to maintain the temperature at the nominal value.

### **Glass Discharge System**

Each HLW melter will have 2 identical and independently operated glass discharge systems located adjacent to each other on a long side of the melter. The glass discharge systems will include the melter glass level detectors, canister glass level detection, riser, airlift lance, trough, and a heated discharge chamber.

The glass discharge from the melter will be initiated by injecting air or an inert gas at the bottom of the airlift riser. As the gas bubbles rise in the glass they will entrain glass in the riser to the inlet of the trough, where the air bubbles burst and the entrained glass flows into the trough. The glass will then be gravity fed through the trough to the pour tip and into the waste container. The rate of glass discharge will be controlled by adjusting the rate at which the air and gas mixture is injected into the bottom of the riser.

The starting and stopping of the glass discharge will be based on the level of glass in the melter. It is desirable to maintain the glass level in the melt pool to within an approximate 1-inch band to reduce thermal stresses on the refractory. Glass discharge operations will be monitored using a camera system to observe the glass pour stream. The level in the waste canister will also be monitored by infrared thermal imaging and gamma level detectors in order to prevent overfilling.

#### **2.4.4 Immobilized HLW Canister Decontamination and Monitoring**

After filling, the cooled IHLW canister will be decontaminated, swabbed, and monitored prior to transfer to the IHLW canister storage area.

A filled, cooled, and welded IHLW canister will be initially washed in a sealed area using medium-pressure demineralized water to remove any loose contamination. After the water wash, the canister will be decontaminated by chemically etching a thin layer of steel from the canister surface, using cerium ion in a dilute nitric acid solution. The canister will then be washed with nitric acid, followed by a second washing with demineralized water. The decontaminated canister will remain in containment to dry. The decontamination fluids will be pumped into a vessel to which hydrogen peroxide is added to neutralize any remaining cerium ion. Potential emissions from the decontamination vessels will be treated through the HLW vessel vent treatment system.

After decontamination and drying, the canister will be swabbed using an automated power manipulator. If the contamination is below acceptable limits, the IHLW canister will be transferred to the IHLW canister storage area. IHLW canisters that exceed the contamination limits will be returned to the decontamination and swabbing station for further processing.

#### **2.4.5 HLW Building Ventilation and Process Offgas Emission Sources**

The emission sources from the HLW vitrification processes include plant building air ventilation, process vessel vents, RFD/PJM exhausts, and HLW melter offgas. The plant building air is expected to contain particulates. The offgases from process vessels and RFD/PJM will contain particulates, volatile organics, and acid gas. The HLW melter offgas will contain particulates, radioactive gases, volatile organics, acid gases, and NO<sub>x</sub> gases at relatively high temperature and moisture content.

NO<sub>x</sub> emissions are expected from the decomposition of metal nitrates and nitrites in the melter feed. Descriptions of NO<sub>x</sub> emissions and proposed controls for the HLW vitrification plant are provided in sections 3 and 4 of this application. Diluted nitric acid tanks at 0.2 molar (M) and 5 M will be stored within the HLW vitrification plant at ambient temperature. However, NO<sub>x</sub> emissions are not expected from these tanks, based on process knowledge.

Insignificant amounts of particulates are expected to be present in the building ventilation systems (less than 0.1 US ton per year). The building ventilation systems are described in section 2.7. Particulate emissions from the HLW vitrification processes are produced from the entrained particulates in the feed and the glass melt. Descriptions of the particulate emissions and proposed controls are provided in sections 3 and 5 of this document.

The particulate and NO<sub>x</sub> emissions calculations for the HLW processes described in sections 2.4.1 through 2.4.4 are provided in Appendix B.

#### **2.4.6 HLW Building Ventilation and Process Offgas Treatment Systems**

The particulate emissions from the building ventilation systems will be treated through HEPA filters.

The HLW RFD/PJM exhausts will be treated through HEPA filters, and routed to the HLW plant stack, where it will be monitored and vented to the atmosphere.

The HLW melter offgas treatment system will consist of the following components.

- Film cooler
- SBS
- Wet electrostatic precipitator
- HEME
- HEPA filter
- Carbon adsorber
- Silver mordenite iodine adsorption unit
- TCO unit
- SCR unit

Particulates will be removed through the HEPA filters. The offgas then passes through a carbon bed adsorber before entering a heat recovery unit and directed to the silver mordenite column for iodine removal. The NO<sub>x</sub> emissions from HLW vitrification processes will be removed primarily through the SCR unit. After the silver mordenite column, the offgas passes through the volatile organic compound catalyst and then enters a chamber where ammonia is injected through an atomized spray and allowed to mix with the offgas. Ammonia is added so that the NO<sub>x</sub> reduction reactions can be carried out. The offgas is treated through the first set of NO<sub>x</sub> catalyst modules. After treatment in the first module, more ammonia is injected into the stream in order to allow further conversion in the second set. The offgas then goes through the second catalyst module. Reduction of NO<sub>x</sub> is also an exothermic reaction; therefore, it significantly increases the offgas temperature so the hot offgas returns to the heat recovery unit. The cooled offgas stream then passes through a set of extraction fans and exits through the stack.

## **2.5 Melter Offgas Maintenance Bypass Systems**

The HLW and LAW melter are equipped with maintenance ventilation lines that bypass the carbon adsorber and the TCO/SCR module. Prior to initiating use of the maintenance ventilation line, waste feed will be halted and the melter placed into an idle condition. Waste feed will not be processed to the melter when the maintenance ventilation line is in use; therefore, NO<sub>x</sub> emissions will not be present in the offgas. The maintenance ventilation line may also be used during commissioning when the plant is running on non-radioactive, non-dangerous simulants.

## **2.6 Analytical Laboratory**

The onsite analytical laboratory will consist of the following systems:

- Analytical radiological laboratory (rad lab) equipment system
- Analytical hot cell laboratory (AHL) equipment system

### **2.6.1 Analytical Radiological Laboratory Equipment System**

The radiological laboratories (rad labs) are designed to support the preparation and analysis of low-to-moderate radioactive samples from the LAW vitrification plant. The rad labs also support the analyses of PT and HLW samples collected and diluted in the hot cell facility. Samples are manually transferred from the hot cell facility to the rad labs. The rad labs are capable of receiving manually transported low-to-moderate activity sample aliquots from the production facilities.

Specifically, the rad labs include the facilities and equipment required to support the following types of activities:

- Total organic and inorganic analyses
- Quantitation of metals and anions
- Organic quantitation
- Radionuclide separation and counting
- Sample receipt and manual transport
- X-ray fluorescence spectrometry and X-ray diffraction analysis
- Distillation/titration
- Ultraviolet and visible spectroscopy

- Fourier transformation infrared spectrometry (FT-IR)
- Preparation of glass samples for elemental analysis
- General physical properties analysis

### **2.6.2 Analytical Hot Cell Laboratory Equipment System**

The AHL equipment system is designed to provide sample preparation, dilution, and dissolution required to support the analyses of production samples collected at the pretreatment and HLW vitrification facilities. This series of hot cells is capable of accepting samples taken automatically from each of the production facilities (using pneumatic transport) and it is also capable of accepting samples that are transported manually. Some of these samples are transported to the hot cells or to the rad labs either directly, after dilution, or after stripping off the radioactive content.

Specifically, the analytical hot cell laboratories will include facilities and equipment required to perform the following activities:

- Sample receipt and transport
- Dilution, fusion, and acid digestion required to prepare samples for subsequent analysis
- Extraction for organic analyses
- General physical properties analysis
- Waste collection and transport

### **2.6.3 Radioactive Solid Waste Management**

Solid and organic lab pack wastes from the rad lab areas are accumulated in the individual laboratories or hot cells. Filled waste drums or containers will then be transferred to the laboratory drum storage area or the waste management cell for waste consolidation, waste packaging, and volume reduction.

### **2.6.4 Radioactive Liquid Waste Disposal**

Liquid effluents from various laboratories or hot cells will be collected into effluent collection vessels. The collected liquids will be transferred to the pretreatment plant for processing.

### **2.6.5 WTP Analytical Laboratory Offgas Emissions**

The WTP analytical laboratory emissions will consist of emissions from building air ventilation, hot cell ventilation, and sample analysis fume hood exhaust. Based on anticipated sampling and analytical activities, insignificant particulate emissions (less than 0.1 US ton per year) are expected. Inorganic emissions have been estimated from laboratory activities and documented in 24590-WTP-RPT-ENV-01-009, *Non-Radioactive Air Emissions Notice of Construction Permit Application for the River Protection Project-Waste Treatment Plant*. As a conservative assumption of particulate emissions, the laboratory inorganic emissions are assumed to be particulates. Based on this assumption, the particulate emissions from the laboratory are estimated to be 0.020 US tons per year. No NO<sub>x</sub> emissions are expected from the laboratory (24590-WTP-RPT-ENV-01-009).



## **2.7 WTP Building Ventilation Systems**

The building air supply for WTP process facilities (pretreatment, LAW vitrification, and HLW vitrification plants) and the analytical laboratory will be divided into 4 numbered zones: C1 to C5 (C4 is not used). The higher number indicates greater contamination potential, and therefore requires a greater degree of control or restriction. A separate zoning system for the ventilation systems will be based on the system for classifying building areas for potential contamination. Zones classified as C5 will have the potential for the greatest contamination, and will include the pretreatment cells, melter cells, and glass pouring and cooling cells. All C5 zones will be operated remotely. Zones classified as C1 will be those areas that have no risk of contamination such as equipment rooms and offices. The overall building ventilation diagrams for the WTP are provided in Figures 2-6, 2-7, 2-8, and 2-9. Based on expected operation activities, NO<sub>x</sub> emissions are not expected from the building ventilation systems.

Confinement will be achieved by maintaining the lowest pressure for areas with greatest contamination (such as C5 areas), with airflows cascading from least- to most-contaminated areas (such as from C1 or C2 to C5 areas). The principle of a cascade system is that air passes through more than one area, effectively reducing the number of separate ventilation streams and, hence, the amount of air requiring treatment.

The confinement provided by physical barriers is enhanced by the ventilation system, which creates a pressure gradient and causes air to flow through engineered routes, from an area of lower contamination potential to an area of higher contamination potential.

### **C1 Ventilation System**

Typically, the C1 areas will consist of offices, workshops, control rooms, and equipment rooms. Emissions are not expected for the C1 areas.

### **C2 Ventilation System**

Typically, the C2 areas will consist of non-process operating areas, access corridors, control and instrumentation, and electrical rooms. Filtered and tempered air will be supplied to these areas by the C2 supply system, and will be cascaded into adjacent C3 areas, or be exhausted by the C2 exhaust system. C2 areas can normally be accessed in street clothes and do not require personal protective equipment.

### **C3 Ventilation System**

Typically, the C3 areas will consist of filter plant rooms, workshops, maintenance areas, and monitoring areas. Access from a C2 area to a C3 area will be through a C2/C3 sub-change room. Air will generally be drawn from C2 areas, and cascaded through the C3 areas, into C5 areas. In general, air cascaded into the C3 areas will be from adjacent C2/C3 sub-change rooms. In some areas, where higher flow may be required into C3 areas, C2/C3 boundary walls will be provided, with engineered transfer grilles equipped with backflow dampers.

If sufficient air cannot be cascaded into a C3 area, a dedicated C2 supply will be provided, with an actuated damper on the C2 supply duct, which will be closed in the event of a loss of C3 extract. This system will shut down in the event of a failure of the C5 exhaust system.

### **C5 Ventilation System**

In general, air cascaded into the C5 areas will be from adjacent C3 areas. If there is a requirement for engineered duct entries through the C3 boundary, they will be protected by backflow dampers and HEPA filters with penetrations through the boundary sealed.

The pretreatment plant C5 areas are designed with the cell or cave perimeter providing radiation shielding, as well as a confinement zone for ventilation purposes. C5 areas typically consist of a series of process cells where waste will be stored and treated. The pretreatment plant hot cell will house major pumps and valves and other process equipment.

The C5 areas in the LAW and HLW vitrification plants will be composed of the following:

- Pour caves
- Transfer tunnel
- Buffer storage area
- C3/C5 drain tank room
- Process cells

Air will be cascaded into the C5 areas and be exhausted by the C5 exhaust system.

## **2.8 Balance of Facilities**

The balance of facilities (BOF) will include, by definition, support systems and utilities required for the waste treatment processes within the pretreatment, LAW vitrification and HLW vitrification plants, and the analytical laboratory. NO<sub>x</sub> and particulate emissions are expected from the steam boilers, generators, and the diesel-driven fire water pumps. Descriptions on NO<sub>x</sub> emissions and proposed controls are provided in sections 3 and 4. Particulate emissions are also expected from the glass former facility. Descriptions on particulate emissions and proposed controls are provided in sections 3 and 5.

### **2.8.1 Diesel Generators**

The BOF contains 3 diesel generators. The generators will provide electrical power to selected equipment and components within the BOF, the pretreatment plant, LAW vitrification plant, and the HLW vitrification plant.

### **2.8.2 Fire Water Pumps**

The BOF contains 2 diesel engine-driven fire pumps. A diesel fuel day tank will be located inside the fire pumphouse in a curbed area. The fire water tanks will be located adjacent to the fire pumphouse. The fire water tanks will be used to store the fire water, which will deliver water to fire hydrants, standpipes, and fixed fire suppression systems.

### **2.8.3 Steam Boilers**

There will be 6 steam boilers at the WTP. The steam boilers will provide process steam and building heat to the pretreatment, the LAW vitrification and HLW vitrification plants, and the laboratories. Non-active

condensate will be returned to the steam plant for reuse in the boilers. Demineralized process water from the water treatment plant will be used as boiler makeup on an as-needed basis.

#### **2.8.4 Glass Former Facility**

A glass former facility will be designed to receive, store, weigh, blend, and transport glass former materials to the LAW and HLW vitrification plants. The glass former facility building provides an enclosed facility that contains the bulk glass former material receipt and unloading area and an outdoor pad for storage silos and material handling equipment. The material receipt and unload area houses a bulk bag material storage area, the bulk bag handling equipment (bulk bag loaders and unloaders), a vacuum unloader, a transporter, the air handling equipment (compressors, air dryers, and receivers that support the glass former handling and pneumatic transport), and an operations office. The outdoor storage area will contain the material storage silos, weight hoppers, transporters, blending silos, and blended glass former transporters. The storage silos and blending silos will have baghouses to minimize emissions during loading and unloading. Transfer of the glass formers between the weigh hoppers, the blending silos, and the melter feed hoppers will occur through sealed, dense-phase pneumatic conveying.

#### **2.8.5 Other Balance of Facilities**

The remaining BOF structures listed below will not produce any particulate or NO<sub>x</sub> emissions.

- Administration building
- Chiller and compressor
- Plant cooling tower
- Field-erected tanks
- Fuel oil pump house
- Nondangerous, nonradioactive liquid effluent tank area
- Switchgear buildings
- Wet chemical storage building
- Water treatment building

Figure 2-1 WTP Process Overview

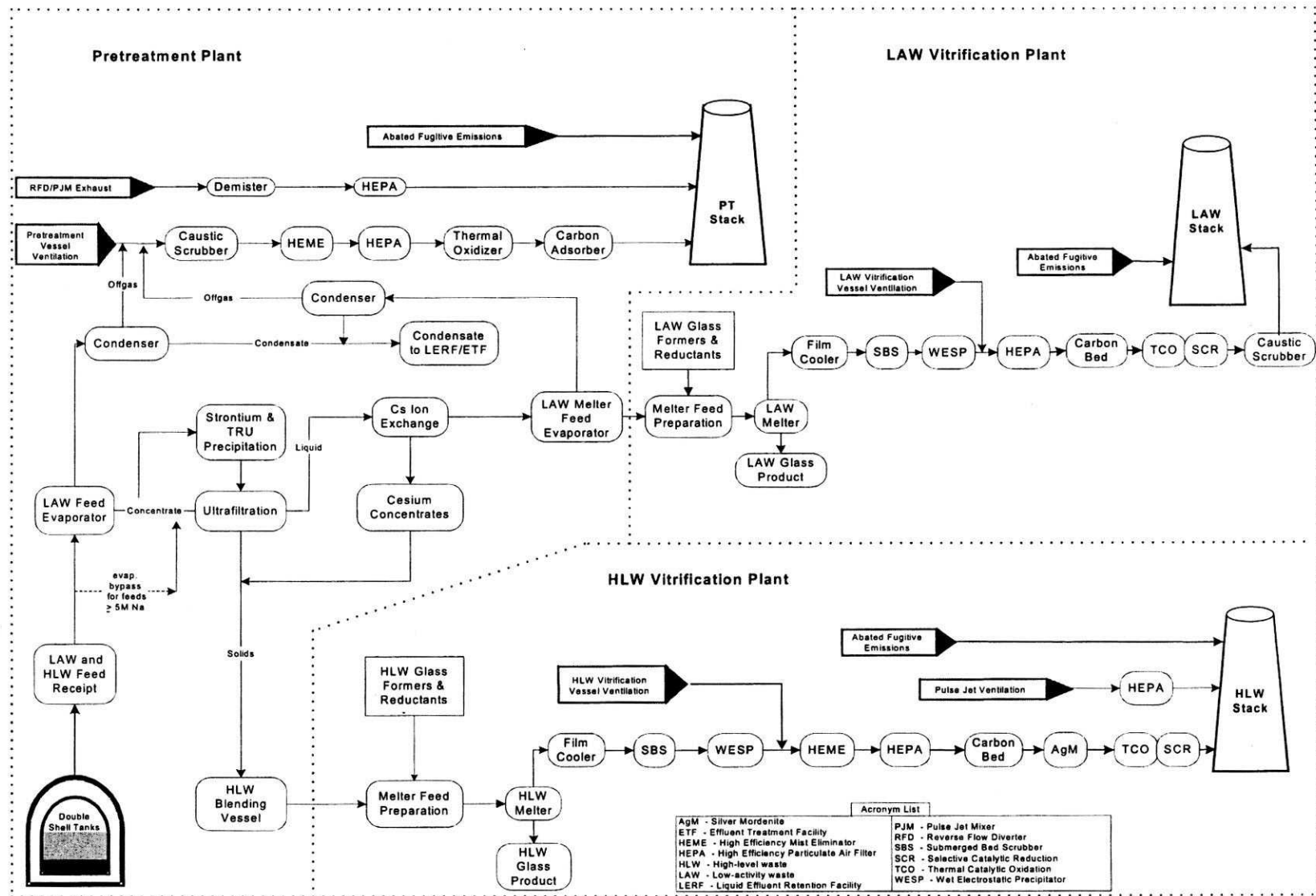


Figure 2-2 Pretreatment Plant Process Overview

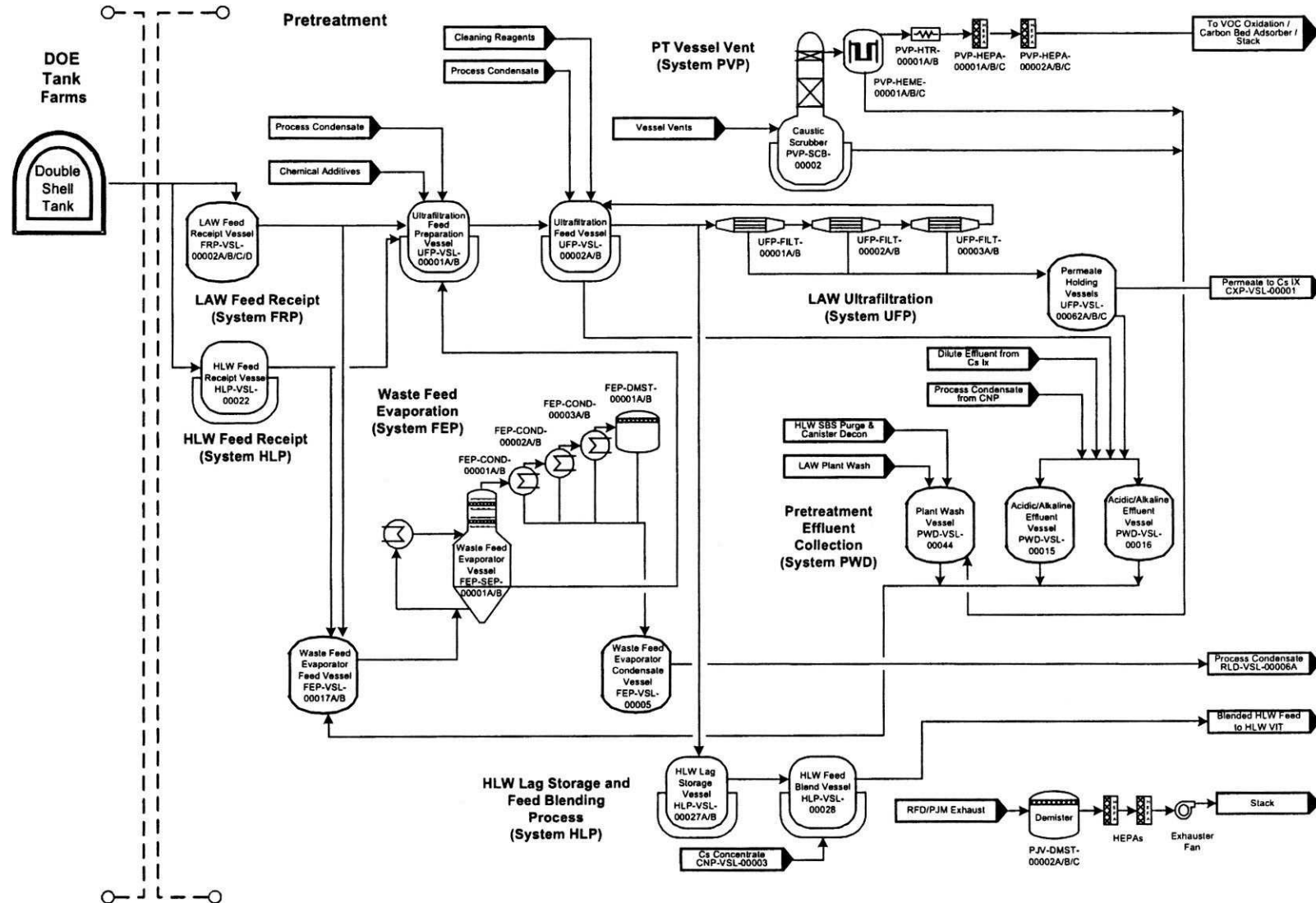
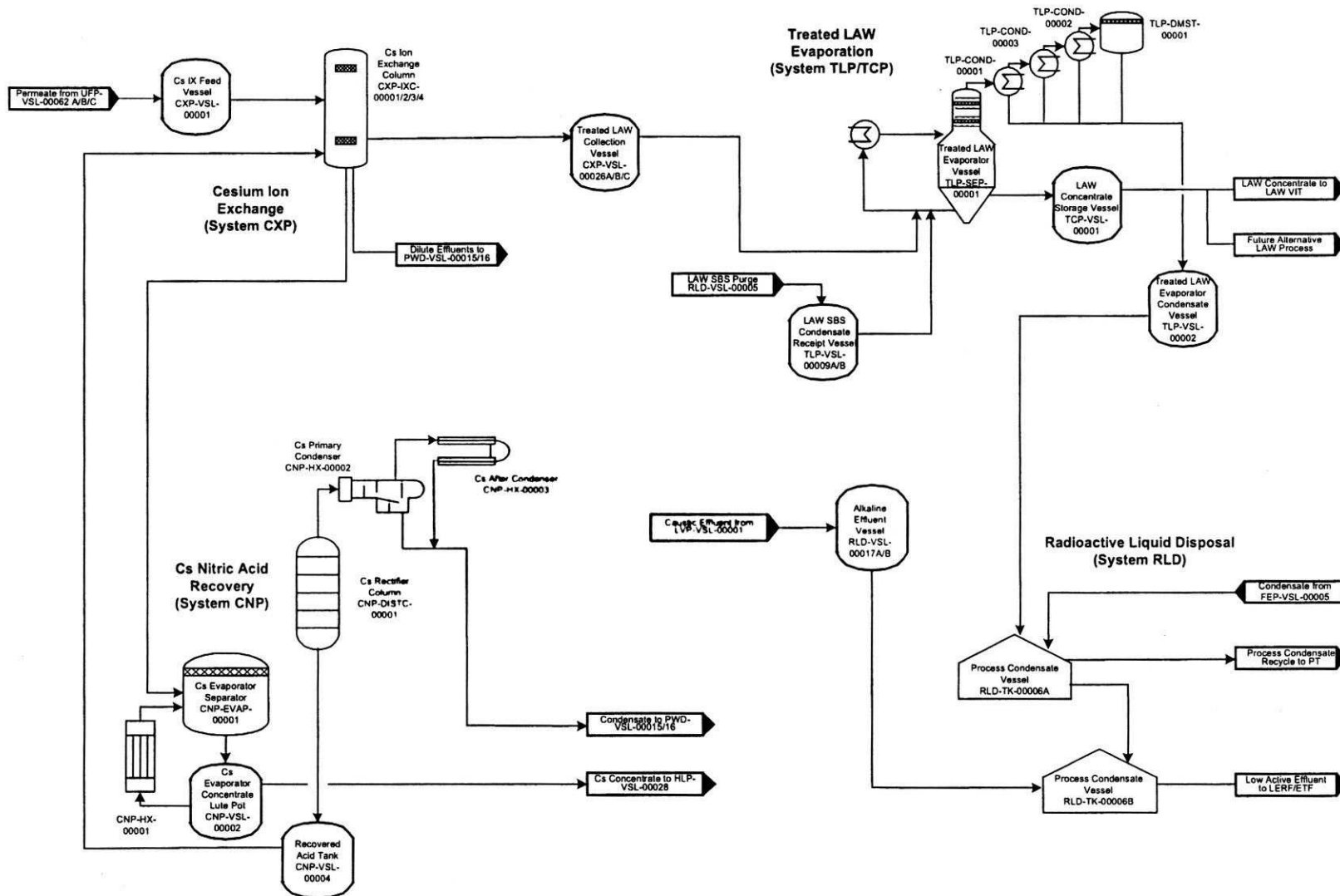
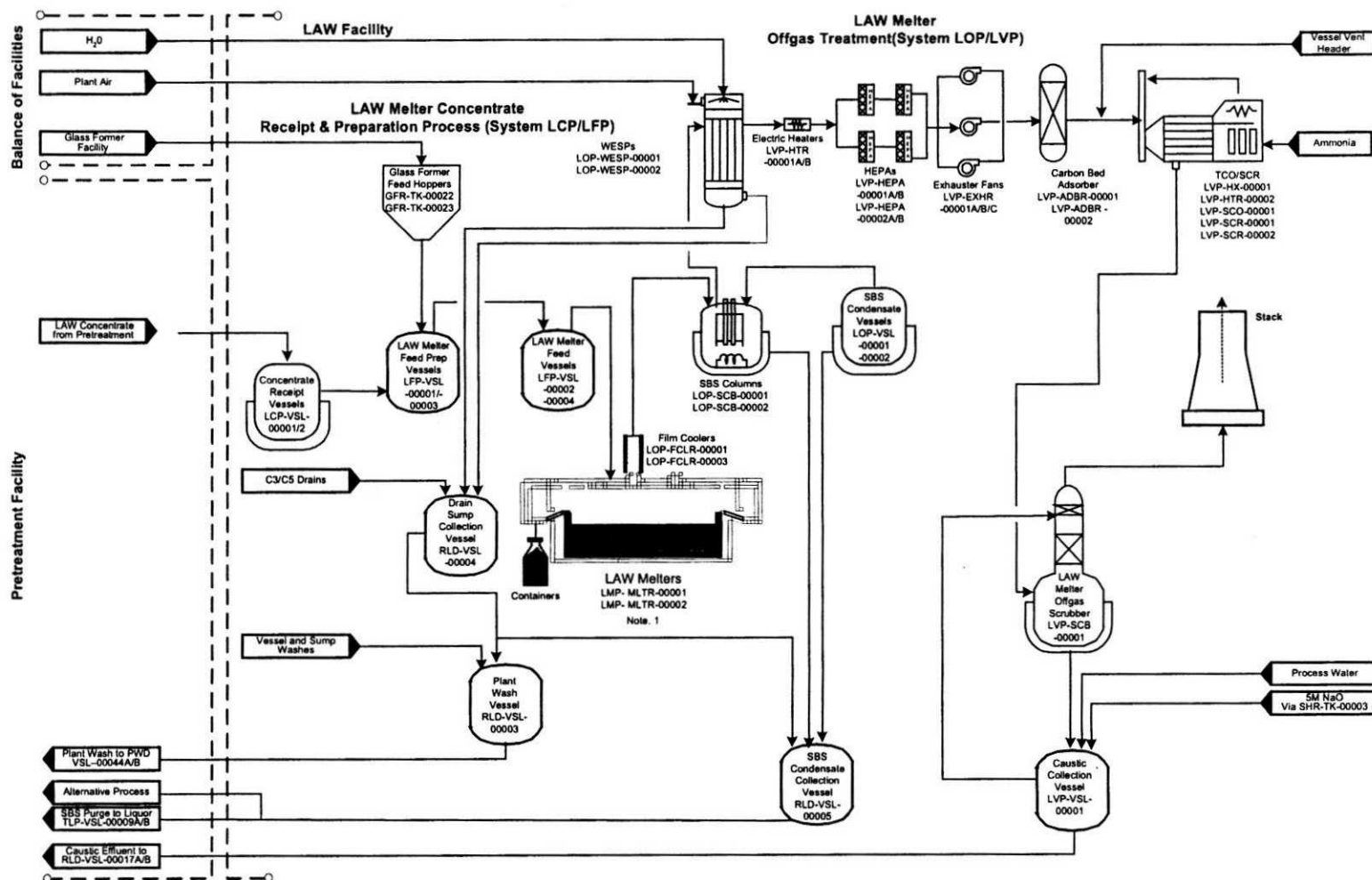


Figure 2-3 Pretreatment Plant Process Overview



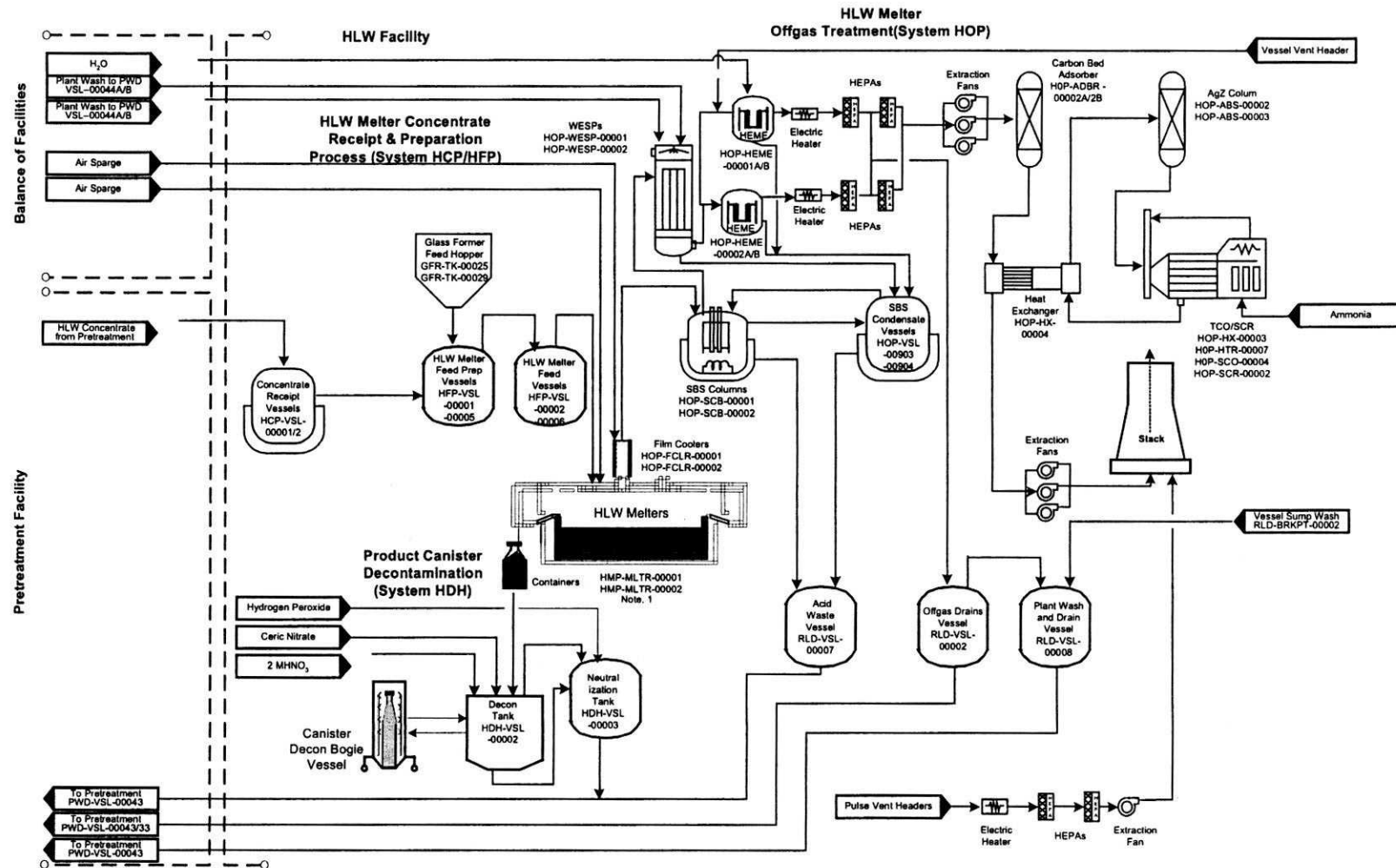
**Figure 2-4 LAW Vitrification Plant Process Overview**



**Notes:**

1. For this diagram one melter system is shown but assumes a total of two LAW melter systems of identical capacity.

Figure 2-5 HLW Vitrification Plant Process Overview



**Notes:**

1. For this diagram one melter system is shown but assumes a total of two HLW melter systems of identical capacity.



Figure 2-6 Pretreatment Building Ventilation Diagram

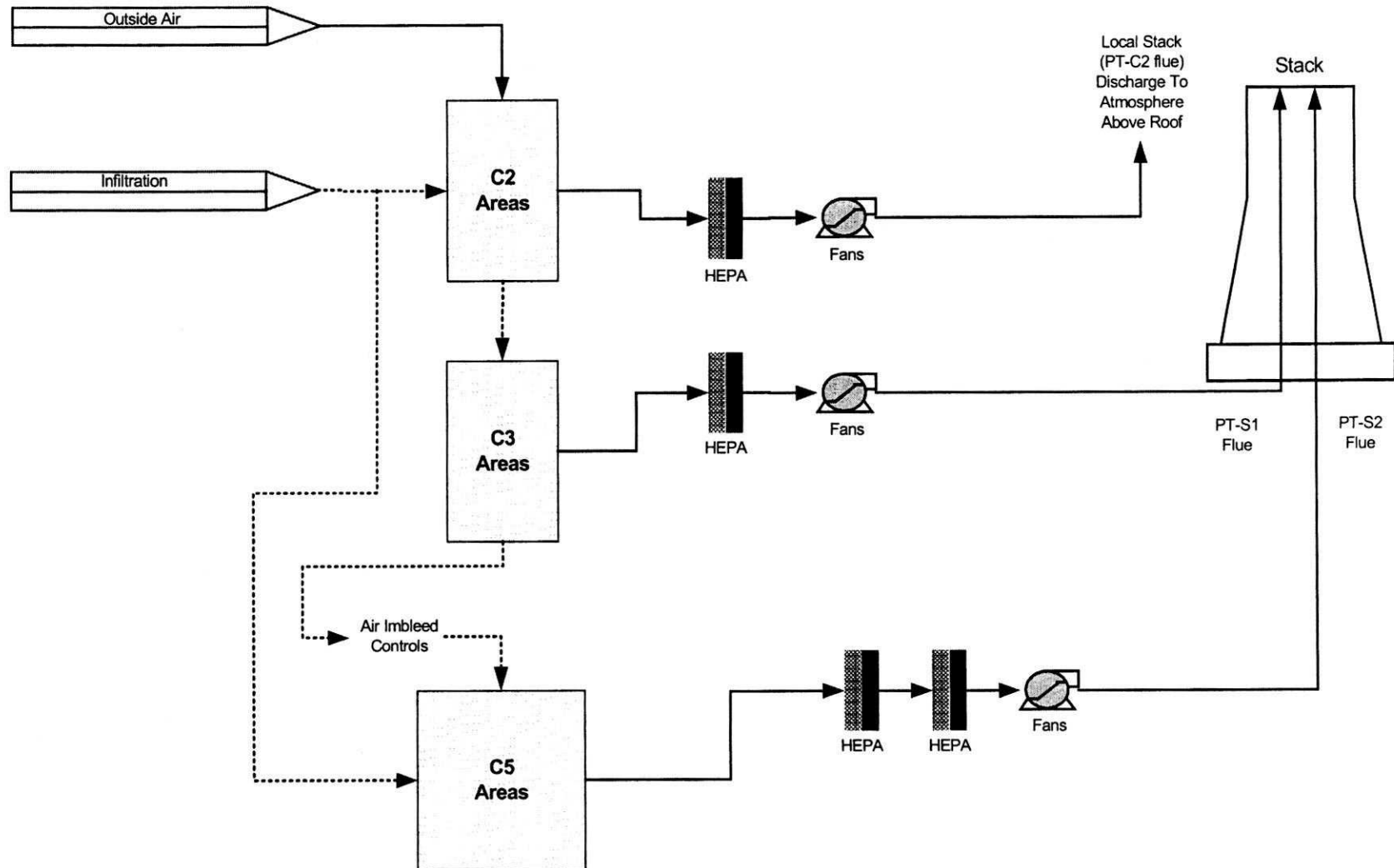


Figure 2-7 LAW Building Ventilation Diagram

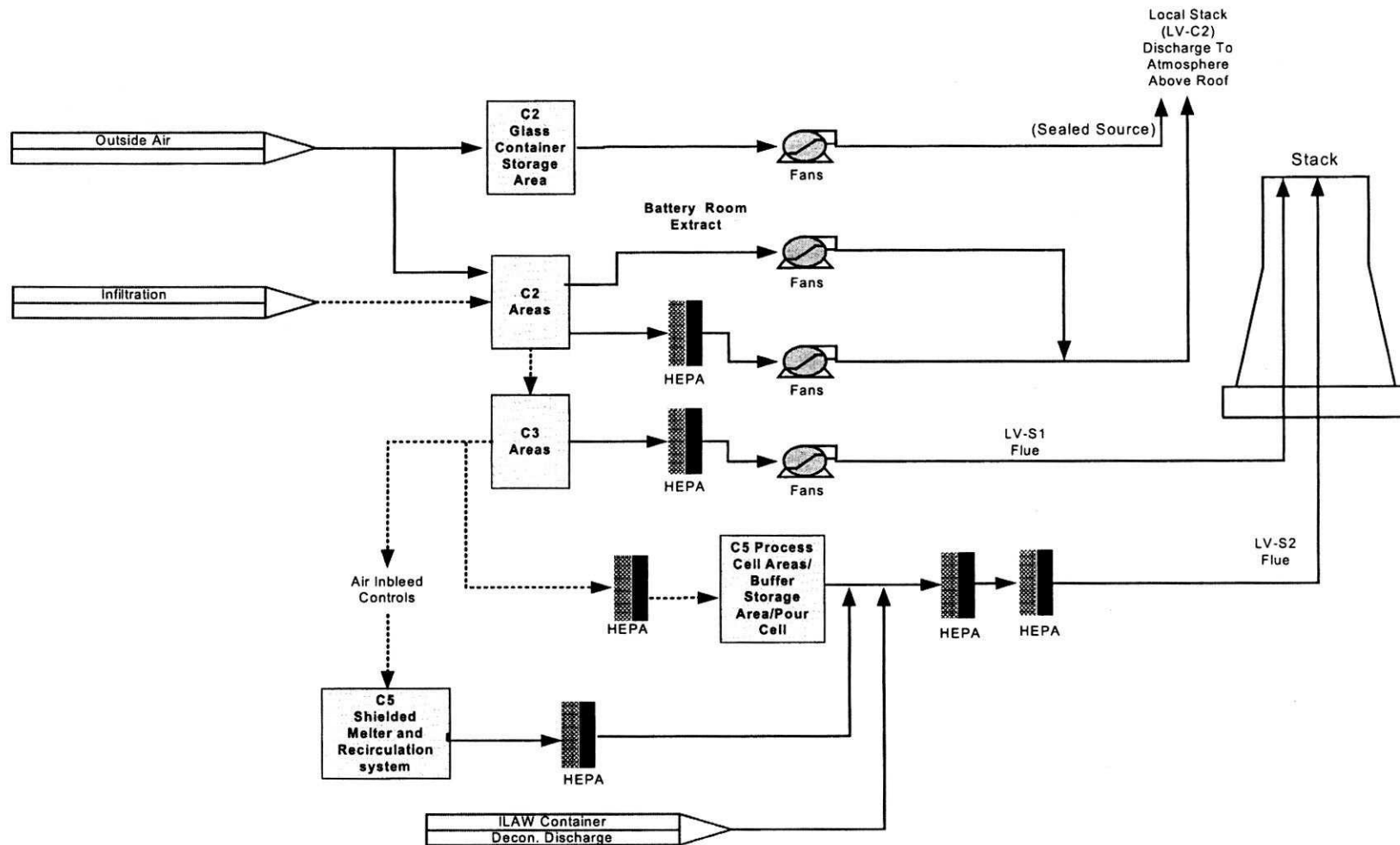


Figure 2-8 HLW Building Ventilation Diagram

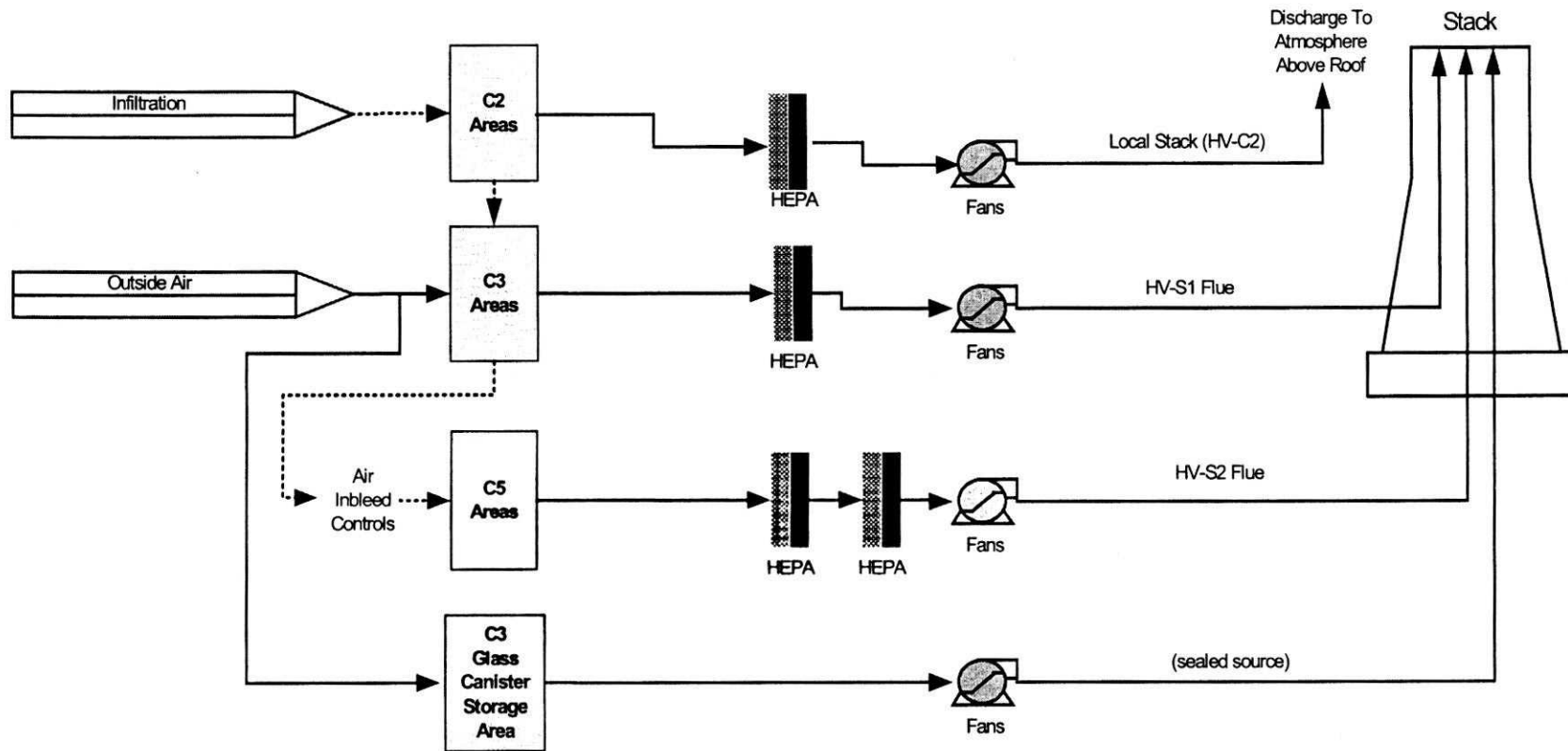
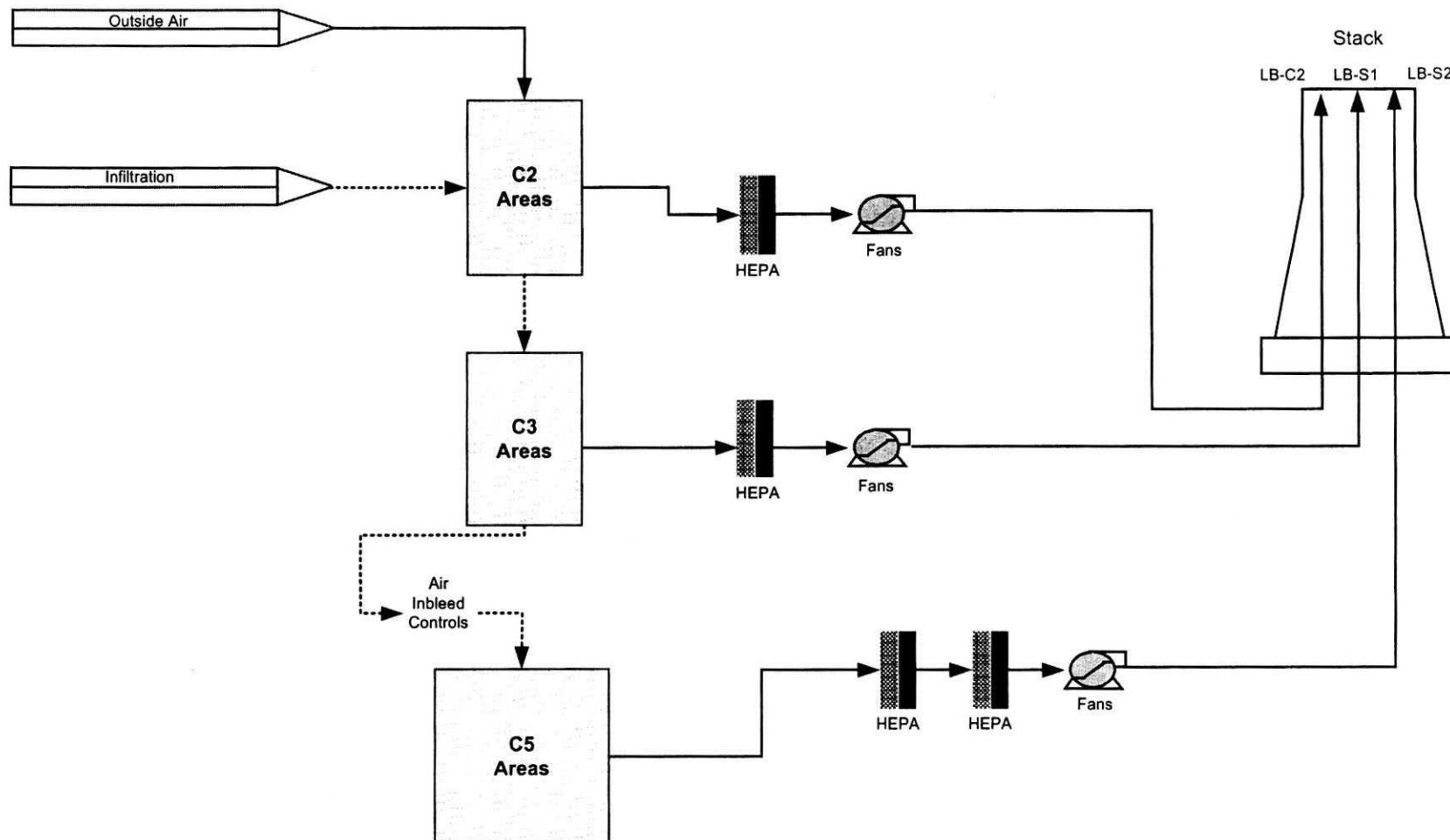


Figure 2-9 Laboratory Ventilation Diagram



## Contents

---

3	Emission Estimates and Applicable PSD Analyses .....	3-1
---	--	-----

## Tables

---

Table 3-1	Annual Facility-Wide Controlled PSD-Regulated Criteria Pollutant Emission Estimates from WTP (US tons per year) <sup>a</sup> .....	3-5
Table 3-2	Annual Facility-Wide Controlled PSD-Regulated Non-criteria Pollutant Emission Estimates from WTP (US tons per year) <sup>a</sup> .....	3-6
Table 3-3	Concentration Estimates from WTP emission points <sup>a</sup> (ppmv) .....	3-7
Table 3-4	Estimated LAW and HLW Melter Systems Oxygen Requirements for Organic Destruction .....	3-8
Table 3-5	Air Sources into Melter Offgas Systems .....	3-8

### 3 Emission Estimates and Applicable PSD Analyses

Federal PSD air quality regulations, 40 CFR 52.21 (j)(3), specify the following:

A major modification shall apply best available control technology for each pollutant subject to regulation under the [Clean Air] Act for which it would result in a significant net emission increase at the source.

Furthermore, the *New Source Review Workshop Manual* (EPA 1990a) states the following:

A separate air quality analysis must be submitted for each regulated pollutant if the applicant proposes to emit the pollutant in a significant amount from a new major stationary source, or proposes to cause a significant net emissions increase from a major modification... Regulated pollutants include (1) pollutants for which a National Ambient Air Quality Standard (NAAQS) exists (criteria pollutants), and (2) other pollutants, which are regulated by EPA, for which no NAAQS exist (noncriteria pollutants).

These requirements apply to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit. There are 5 areas within the WTP that have the potential to release air pollutants regulated by PSD to the environment:

- Pretreatment facilities
- LAW vitrification
- HLW vitrification
- BOF

A summary table showing the controlled, facility-wide emissions of PSD-regulated pollutants for each of these operations has been developed. Table 3-1 and Table 3-2 present the emissions in US tons per year for PSD-regulated criteria and the PSD-regulated non-criteria pollutants, as well as the applicable PSD-regulated significant net emissions increase levels. Table 3-3 presents the emission concentrations in parts per million by volume (ppmv). The emissions estimate details for pretreatment, LAW vitrification, and HLW vitrification processes are presented in Appendix B. An onsite analytical laboratory will be provided for the WTP; however, insignificant amounts of PSD-regulated air pollutants are expected, based on the small number of samples and small sample volume to be handled.

The BOF includes 4 sources of PSD-regulated emissions: boilers, diesel generators, diesel engines for the fire water pumps, and the glass former facility. The boilers will be used to produce process steam and building heat, and the generators will be used to maintain facility power during power outages. The emission estimate details for the boilers, the diesel generators, the fire water pump diesel engines, and the glass former facility are provided in Appendix B.

Table 3-1 and Table 3-2 present the emission limits for each pollutant that is defined as a significant increase under PSD. Comparing these limits to those of the total estimated PSD pollutant emissions from the WTP allows a determination to be made regarding which pollutants are "significant" under PSD

regulations. As shown in Table 3-1 and Table 3-2, nitrogen oxides (NO<sub>x</sub>) and particulate matter (PM) have exceeded their corresponding PSD significance limits. Therefore, the BACT and the air quality impact analyses under PSD will cover the evaluation of NO<sub>x</sub> and PM emissions, control technologies, and ambient air quality impacts resulting from the WTP.

### NO<sub>x</sub> Concentration Oxygen Correction

Table 3-3 presents the concentration estimates for the process emission units, boilers, diesel generators, and fire water pump NO<sub>x</sub> emissions. It is a common practice for Ecology, when issuing PSD permits, to require correcting concentration-based emission limits to a standard oxygen (O<sub>2</sub>) value. The boiler NO<sub>x</sub> concentration estimate has been corrected to 3 % O<sub>2</sub>. The diesel generator and fire pump NO<sub>x</sub> concentration estimate has been corrected to 15 %.

The pretreatment, LAW vitrification, and HLW vitrification concentration estimates have not been corrected to a standard O<sub>2</sub> value because the WTP does not believe using this approach is justified. The WTP vitrification process is different from other combustion sources in the following ways:

- 1 The melters are electrically heated rather than using fossil fuel combustion sources; therefore, the heating process itself does not consume O<sub>2</sub>.
- 2 The process consumes only a minimal amount of oxygen for organics destruction.
- 3 Air is used in the melter and offgas systems for various purposes, such as operating various offgas control equipment, maintaining the system under negative pressure to eliminate contamination spread in the plant, and ventilating process vessels.

The consequence of the operational conditions listed above is that the dry oxygen concentrations in the melter exhaust approaches the atmospheric oxygen concentration of 21 %, and no O<sub>2</sub> correction is necessary. The following discussion provides a more complete explanation of the WTP operating conditions listed above.

The Washington Department of Ecology determined that the WTP will be permitted as a miscellaneous unit under the dangerous waste regulations WAC 173-303-680, *Miscellaneous Units*. As part of the permitting process, Ecology has concluded that certain air emission limits contained in 40 CFR Part 63 Subpart EEE, *The Hazardous Waste Combustion Maximally Achievable Control Technology Standard (MACT)*, apply to the WTP as environmental performance standards that are protective of human health and the environment.

The MACT standard emission limits are all standardized to a dry, standard cubic meter, and are corrected to 7 % O<sub>2</sub>. This correction value was selected because incinerators and other combustion equipment operates most efficiently at 7 % O<sub>2</sub> by volume. Since the emission limits are concentration-based standards, operators of hazardous waste combustion equipment would have had the opportunity to meet the limits by adding dilution air to the stack, thereby circumventing the intent of the emission standards. The US Environmental Protection Agency subsequently revised their regulations to preclude compliance by dilution.

The MACT regulations were written for incinerators, which are designed to operate efficiently at a nominal combustion chamber O<sub>2</sub> content of 7 %. Typical incinerators combust waste materials together with supplemental fuel at a rate intended to achieve a combustion temperature sufficient to destroy organic constituents in the feed. Incinerators are also supplied with combustion air at a ratio that is in excess of the quantity needed for combustion of the organic compounds in the waste and supplemental

fuel feeds. The excess air and supplemental fuel quantities are simultaneously controlled to achieve the desired excess air conditions and combustion chamber temperature necessary for destruction of the organic waste compounds. Large deviations in the amount of excess air will affect the combustion chamber temperature and impact the destruction efficiency of organic compounds. Therefore, the steady state oxygen content for most incinerators does not vary by more than 1 to 2 % (that is,  $7 \% \pm 1 \%$  to 2 %).

The WTP vitrification units, on the other hand, are controlled in a completely different manner than an incinerator. The major constituents in the feed to the vitrification units are approximately 50 wt % water and 50 wt % inert solids. The organic content in the LAW feed is mostly sucrose (up to 4.4 % of the feed), for LAW composition Envelopes A and B. Envelope C has approximately the same mass fraction of organics present in the waste itself. These organics are principally oxalates and chelating compound residues (that is, ethylene diamine tetra-acetic acid [EDTA]). Consequently, the project adds a reduced quantity of sugar in Envelope C melter feed formulations. The HLW, on the other hand, may or may not require sugar for glass chemistry control. If sugar were used, it would be on the order of 0.5 wt % of the feed (wet basis). Some incinerators also receive high water and inert water wastes; however, incinerators require a significant amount of supplemental fuel to process these wastes, and this fuel lowers the oxygen content of the exhaust gases. The WTP melter units use alternating current joule heating instead of fossil fuel to process the waste. The amount of air that combusts with the small amount of organics in the feed is trivial compared to the large amount of air available in the melter, and, hence, the melter unit operates at a high exhaust oxygen concentration. Waste vitrification chemistry, with the possible exception of glass redox control, is independent of the air present in the melter system.

Based on 24590-WTP-M3C-HOP-00001, *WTP Process Engineering Heat and Material Balance Calculations*, the melter feed organic content consists of the following components: non-volatile, semi-volatile, and sucrose components.

	<u>Non-volatile (%)</u>	<u>Semi-volatile (%)</u>	<u>Sucrose (%)</u>
LAW	0.1	0.1	4.4
HLW	0.1	0.1	1.1

Approximately 50 % of the sucrose is estimated to react with the feed constituents, principally reduction reactions with nitrates feed. The remaining non-volatile organics, semi-volatile organics, and sucrose react with air in the offgas treatment system. The net amount of oxygen required by the LAW and HLW melter systems for oxidation of the organics after reduction by the amount of oxygen liberated by oxy-anion decomposition in the glass are summarized in Table 3-4. In comparing the net oxygen requirement to the stack oxygen content, the oxygen required for destruction of the feed organic constituents is insignificant relative to the total amount of oxygen in the system.

Because only a minimal amount of the oxygen is consumed in the melters for the destruction of organics, the dry oxygen concentration in the melter exhaust approaches the dry standard atmospheric oxygen concentration of 21 %.

Air is used in the melter and its offgas systems to operate components, provide negative pressure control, and ventilate process vessels. Consumption of oxygen is not fundamental to the operation of the melter, in contrast to an incinerator. It is necessary to hold the melter under negative pressure to prevent the spread of contamination and to protect workers. The melter is held under slight negative pressure ( $-5$  inches of water [ $H_2O$ ]). This results in significant air in-leakage (on the order of 100 standard cubic feet per minute [scfm] for the HLW melter to 300 scfm for the LAW melter) into the melter plenum. The



project has incentive to minimize air inputs because emission control equipment size is a function of air volume, and because the efficiency of some of the pollution control equipment is a function of concentration. Sources of air into the melter offgas systems are provided in Table 3-5.

After considering the process description provided above, Ecology determined that correcting MACT concentration limits to 7 % was technically inappropriate. The following comes from the *Fact Sheet for the Hanford Facility Resource Conservation and Recovery Act Draft Permit For the Treatment, Storage, and Disposal of Dangerous Waste*, Publication Number 01-05-006 (Ecology 2002).

Air is used in the LAW and HLW Vitrification Systems to operate components, provide negative pressure control, and ventilate process vessels. Compared to an incinerator the consumption of oxygen in the melters is not significant as the melters use electrical heating instead of fossil fuel to process the waste. The lack of significant consumption of oxygen in the melters combined with the large inputs of air into the LAW and HLW Vitrification Systems to operate components, provide negative pressure control, and ventilate process vessels, results in high oxygen levels in the LAW and HLW Vitrification Systems' exhaust. The standard correction of emission standards to 7% oxygen for incinerators is not being applied to the LAW and HLW Vitrification Systems, as it is technically inappropriate.

Many PSD-permitted sources (especially combustion sources such as incinerators, boilers, and generators) are required to correct concentration-based emission limits to a standard oxygen concentration. As discussed above, this is done to ensure that combustion processes are operating at peak efficiency and to prevent the addition of dilution air in order to meet concentration-based emission limits. These conditions may require the installation of a continuous oxygen monitor in the offgas system in order to monitor combustion conditions.

Additionally, a continuous oxygen monitor may be installed as a component of a NO<sub>x</sub> continuous emissions monitoring system. 40 CFR 60 Appendix B, *Performance Specification 2 – Specifications and Test Procedures for SO<sub>2</sub> and NO<sub>x</sub> Continuous Emission Monitoring Systems in Stationary Sources*, states: "The CEMS **may** (emphasis added) include, for certain stationary sources, a diluent [air] (O<sub>2</sub> or CO<sub>2</sub>) monitor." The performance specification implies that a continuous oxygen monitor may not be required for all stationary sources. Since the melter offgas oxygen concentrations will be very near atmospheric oxygen concentrations (greater than 20 %), there is no need to correct the offgas NO<sub>x</sub> concentration to a standard oxygen concentration less than 20 %. And because correcting the LAW and HLW vitrification NO<sub>x</sub> emission concentrations to a standard oxygen value is technically inappropriate, there is no need to install a diluent air monitor in the LAW and HLW monitoring systems.

### **Fugitive Emissions**

It should be noted that under PSD regulations, fugitive emissions are those "which could not reasonably pass through a stack, chimney, vent or other functionally equivalent opening" (40 CFR 52.21(b)(20)). Since the WTP does not fall into 1 of the 28 named PSD source categories (with 100 US tons per year major source threshold levels), fugitive emissions do not have to be included in the potential to emit summary to determine the significance of pollutant emissions (EPA 1990a).

**Table 3-1 Annual Facility-Wide Controlled PSD-Regulated Criteria Pollutant Emission Estimates from WTP (US tons per year)<sup>a</sup>**

Criteria Pollutant	Pretreatment Facilities	LAW Vitrification Facility	HLW Vitrification Facility	Boiler Plant	Diesel Generators	Miscellaneous Facility Sources <sup>b</sup>	Total Emissions	PSD Significance Limits
CO	7.94E-21	2.20	0.36	65.6	2.4	0.02	70.59	100
NO <sub>x</sub>	0.44	36.7	8.5	84.3	20.4	0.4	150.68	40
SO <sub>2</sub>	1.09E-21	3.68	4.84	2.9 <sup>d</sup>	0.03 <sup>d</sup>	6.0E-04 <sup>d</sup>	11.47	40
PM <sub>10</sub> <sup>b,c</sup>	2.03	1.57	1.18	18.7	0.7	0.06	24.25	15
VOCs (as total volatile and semi-volatile organics)	3.84	0.47	0.38	28.1	0.8	0.01	33.60	40
Pb	1.03E-09	2.65E-9	1.99E-11	8.43E-03	4.7E-03	3.99E-04	0.01	0.6

Notes:

- a See Appendix B for detailed emissions calculations and assumptions.
- b Miscellaneous BOF source emissions represent the emissions from the diesel engines that will be used for the fire water pump and particulate emissions from the glass former facility.
- c All particulate matter is assumed to be PM<sub>10</sub>.
- d Ultra-low sulfur fuel (30 ppm, 0.003%) was used for estimating emissions for the steam boilers, generators, and fire pumps.

**Table 3-2 Annual Facility-Wide Controlled PSD-Regulated Non-criteria Pollutant Emission Estimates from WTP (US tons per year) <sup>a</sup>**

Non-criteria Pollutant	Pretreatment Facilities	LAW Vitrification Facility	HLW Vitrification Facility	Boiler Plant <sup>b</sup>	Diesel Generators <sup>b</sup>	Fire Water Pump <sup>b</sup>	Total Emissions	PSD Significance Limits
Fluorides	1.25E-08	3.76E-07	8.86E-13	0.00	0.00	0.00	3.88E-07	3
H <sub>2</sub> SO <sub>4</sub> Mist	1.86E-08	1.79E-11	1.57E-14	0.00	0.00	0.00	1.87E-08	7
H <sub>2</sub> S	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10
Total Reduced Sulfur	3.76E-14	3.68E-01	4.84E-01	0.00	0.00	0.00	0.85	10
Ozone Depleting Substances <sup>c</sup>	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100

Notes:

- a See Appendix B for detailed emissions calculations.
- b No emission factors are available for boilers and generators/pump engines for the PSD-regulated non-criteria pollutants.
- c Ozone depleting substances are not expected at WTP.

**Table 3-3 Concentration Estimates from WTP emission points <sup>a</sup> (ppmv)**

Pollutant	Pretreatment Facilities (ppmv) <sup>c</sup>	LAW Vitrification (ppmv) <sup>c</sup>	HLW Vitrification (ppmv) <sup>c</sup>	Boilers (ppmv) <sup>c</sup> Corrected to 3 % O <sub>2</sub>	Diesel Generator 3950 hp (ppmv) <sup>c</sup> Corrected to 15 % O <sub>2</sub>	Diesel Generator 5530 hp (ppmv) <sup>c</sup> Corrected to 15 % O <sub>2</sub>	Fire Water Pump (ppmv) <sup>c</sup> Corrected to 15 % O <sub>2</sub>
NO <sub>x</sub>	6	477	352	82	943	1240	507
PM <sub>10</sub> <sup>b</sup>	NA	NA	NA	N/A	N/A	N/A	N/A

Notes:

- a See Appendix B for detailed calculations.
- b All particulate matter is assumed to be PM<sub>10</sub>.
- c Concentration expressed as dry parts per million by volume

**Table 3-4 Estimated LAW and HLW Melter Systems Oxygen Requirements for Organic Destruction**

Organic Constituents	LAW, Gram-Mole per Hour		HLW, Gram-Mole per Hour	
	Organic	Oxygen	Organic	Oxygen
non-volatile organic compounds <sup>a</sup>	4.08	44.90	1.42	17.10
semi-volatile organic compounds <sup>b</sup>	9.31	112.00	5.22	42.40
Sucrose	72.10	866.00	5.34	64.10
Anion Decomposition				
NO <sub>3</sub> <sup>-</sup>		-287.00		-25.00
NO <sub>2</sub> <sup>-</sup>		-207.00		-18.20
SO <sub>4</sub> <sup>2-</sup>		-37.60		-2.30
Net Oxygen Requirement		491.30		78.10
Stack Oxygen Content		49,100		17,400

a non-volatile organic compounds are assumed to be EDTA (C<sub>10</sub>H<sub>16</sub>N<sub>2</sub>O<sub>8</sub>)

b semi-volatile organic compounds are assumed to be Naphthalene (C<sub>10</sub>H<sub>8</sub>)

**Table 3-5 Air Sources into Melter Offgas Systems**

Source	Nominal Standard Cubic Feet per Minute	Purpose
melter in-leakage	100 to 300	Consequence of holding melter at negative pressure
injections to melter	50 to 100	Required to keep nozzles clear, protect equipment, run bubblers
film cooler	200 to 400	Required to prevent solids accumulation / plugging
control air	100 to 300	Required for melter pressure control system
vessel vent	100 to 200	Required to maintain process vessels under slight negative pressure. Vessel vent air is slightly contaminated and must be filtered.

## Contents

<b>4</b>	<b>Best Available Control Technology (BACT) Analysis .....</b>	<b>4-1</b>
4.1	BACT Analysis Methodology .....	4-1
4.1.1	Step 1 - Identification of All Control Technology Options.....	4-1
4.1.2	Step 2 - Elimination of Technically Infeasible Control Options.....	4-2
4.1.3	Step 3 - Ranking of Technically Feasible Control Options.....	4-3
4.1.4	Step 4 - Evaluation of Most Effective Control Options .....	4-3
4.1.5	Step 5 - Selection of BACT .....	4-4
4.2	NO <sub>x</sub> BACT for Pretreatment Processing .....	4-4
4.3	NO <sub>x</sub> BACT for LAW Vitrification Processing.....	4-4
4.3.1	Identification of Control Technology Options .....	4-5
4.3.2	Elimination of Technically Infeasible Options .....	4-11
4.3.3	Ranking of Remaining Control Technologies by Control Efficiency .....	4-13
4.3.4	Evaluating the Most Effective Controls.....	4-13
4.3.5	Selection of the Proposed Best Available Control Technology for LAW .....	4-15
4.4	NO <sub>x</sub> BACT for HLW Vitrification Processing.....	4-15
4.4.1	Identification of Control Technology Options .....	4-16
4.4.2	Elimination of Technically Infeasible Options .....	4-16
4.4.3	Ranking of Remaining Control Technologies by Control Efficiency .....	4-17
4.4.4	Evaluating the Most Effective Controls.....	4-17
4.4.5	Selection of the Proposed Best Available Control Technology .....	4-19
4.5	NO <sub>x</sub> BACT for the Steam Boiler Plant.....	4-19
4.5.1	Identification of Control Technology Options .....	4-20
4.5.2	Technical Feasibility Considerations .....	4-30
4.5.3	Control Technology Hierarchy .....	4-31
4.5.4	Energy, Economic, and Environmental Impacts.....	4-32
4.5.5	Selection of Proposed BACT.....	4-32
4.6	NO <sub>x</sub> BACT for the Auxiliary and Support Systems.....	4-32
4.7	Summary of Proposed BACT for NO <sub>x</sub> Emissions Control for the WTP.....	4-33

## Tables

Table 4-1	Wet NO <sub>x</sub> Abatement Technologies.....	4-34
Table 4-2	Dry NO <sub>x</sub> Abatement Technologies .....	4-35
Table 4-3	NO <sub>x</sub> Abatement Technologies.....	4-36
Table 4-4	Ranking of Technically Feasible Control Technologies by Expected Control Efficiency.....	4-37
Table 4-5	Summary of Cost Analysis for LAW Vitrification Plant.....	4-38
Table 4-6	Summary of Cost Analysis for HLW Vitrification Plant.....	4-38
Table 4-7	NO <sub>x</sub> Control Options for Oil-Fired Boilers <sup>a</sup> (Boilrank).....	4-39
Table 4-8	EPA RBLQ Query Results - NO <sub>x</sub> Control - No. 2 Fuel Oil Fired Boilers .....	4-42
Table 4-9	Summary of Proposed BACT for NO <sub>x</sub> .....	4-43

## 4 Best Available Control Technology (BACT) Analysis

### 4.1 BACT Analysis Methodology

An analysis has been conducted to demonstrate that the BACT has been applied to the WTP. The PSD requirements for the WTP are invoked by WAC 173-400-141, *Prevention of Significant Deterioration*. The requirement to conduct a BACT analysis is set forth in Section 165(a)(4) of the CAA, in federal regulations in 40 CFR 52.21(j).

The BACT requirement is defined as:

...an emission limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source of modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61 (EPA 1990b).

On 1 December 1987, former EPA Assistant Administrator for Air and Radiation, J. Craig Potter, issued a memorandum implementing a number of program initiatives aimed at improving the effectiveness of the CAA new source review program. The implementation of a top-down approach to determine the BACT under PSD is among these initiatives. In short, the top-down process requires that the most stringent, feasible control technology is evaluated first in a BACT analysis. In a top-down analysis, all available control technologies for the particular pollutant in question are listed and ranked in descending order of control effectiveness. The most stringent, feasible control technology represents BACT, unless the applicant can demonstrate that this level of control is not reasonably warranted because of site-specific energy, environmental, or economic impacts. If the most stringent, feasible control technology is determined to be unachievable, the next most stringent level of control is to be evaluated. This process continues until a technology cannot be eliminated on the basis of energy, environmental, or economic considerations. The highest-ranked control technology not eliminated is deemed BACT for the particular pollutant for the specific project being evaluated (Calcagni 1989).

The following discussion describes, in greater detail, the top-down procedure that has been applied in order to determine the BACT for emissions of NO<sub>x</sub> from emission sources within the WTP facility. The BACT approach consists of 5 steps, which are consistent with guidance prepared by the EPA's Office of Air Quality Planning and Standards and are presented in the *New Source Review Workshop Manual-Prevention of Significant Deterioration and Nonattainment Area Permitting* (EPA 1990a).

#### 4.1.1 Step 1 - Identification of All Control Technology Options

The first step in a top-down analysis is to identify available control options for each emission unit in question. This list should be comprehensive and should include technologies with a practical potential to

reduce emissions of the pollutant from the emission unit. Control technology alternatives include existing controls for the source category and controls that have been applied to similar source categories and gas streams and, therefore, present the opportunity for control technology transfer. Possible control alternatives to be considered will include innovative or developmental control technologies or any potential technologies that are used outside the United States. In general, emission controls that have not been successfully permitted, applied, or demonstrated on full-scale operations are not considered available. For a technology to be considered available, an applicant should be able to purchase or construct a process or device that has been demonstrated in practice (EPA 1990b). Technologies that have been identified in lowest achievable emission rate (LAER) determinations are to be considered for BACT analysis, usually as the top alternative.

EPA's BACT determination guidance organizes the potential control technologies to be considered into 3 groups:

- Lower-emitting processes or practices (that is, the use of materials or processes that prevent or minimize the production of emissions and, therefore, result in lower emission rates)
- Add-on control equipment (that is, the use of equipment that captures, controls, and reduces emissions after they are produced)
- Combinations of lower-emitting processes and add-on control equipment (EPA 1990b)

Lower-emitting processes will be evaluated based on manufacturing or processing of identical or similar materials from identical or similar raw materials or fuels. In conformance with EPA's traditional interpretation of lower-emitting process alternatives, the WTP BACT analysis will consider alternative methods or practices that can be applied to the process, rather than alternatives to the process itself. The WTP system is designed with the environmentally beneficial objective of permanent immobilization of radioactive wastes for disposal. PSD pollutants are byproducts of this process, and the control system is designed to minimize criteria pollutant emissions. However, the primary design goal of the system is to ensure complete, safe, and proper immobilization of LAW and HLW waste feeds in order to form ILAW and IHLW materials.

#### **4.1.2 Step 2 - Elimination of Technically Infeasible Control Options**

Once all potentially applicable options have been identified, the technical feasibility of each option is evaluated. If a control technology has been installed and successfully operated on the type of source under review, the control technology is demonstrated and is technically feasible. If a control option has not been demonstrated as described previously, the analysis must consider the availability and applicability of the control option. An available technology is one that can be obtained through commercial sales and licensing. An available technology is applicable if it can be reasonably installed and operated on the source under consideration. A commercially available control technology is presumed to be applicable if it has been, or is soon to be, deployed on the same or a similar source. In the absence of a demonstration, a detailed case-specific analysis is required to demonstrate that based on physical, chemical, and engineering principles, technical difficulties would preclude the successful use of the control option on the emission unit under review. Unless significant differences among source types exist that are pertinent to the successful operation of the control option, and unless the applicant can present information to the contrary, the option is presumed to be technically feasible. The comparison of source types should be made between the physical and chemical characteristics of the exhaust gas from the unit under review, and those characteristics of the unit from which the technology is to be transferred (EPA 1990b). Any options that are deemed to be technically infeasible can be eliminated from further consideration in the BACT analysis.



#### 4.1.3 Step 3 - Ranking of Technically Feasible Control Options

The options deemed to be technically feasible are next analyzed to determine their overall effectiveness in reducing the pollutant in question for each emission unit. A hierarchy that lists the control option with the lowest emissions level as the top option will be established. Each of the other options will be listed after the top alternative, and ranked from lowest to highest emissions (most-effective to least-effective emissions control alternative). The following types of information should be presented for each pollutant or emission unit combination in the control options hierarchy, where applicable:

- Emissions performance (control efficiencies, stack concentrations)
- Expected emission rate (pounds per hour, US tons per year)
- Expected emission reduction (US tons per year)
- Economic impacts (total annualized costs, cost effectiveness, incremental cost effectiveness)
- Environmental impacts
- Energy impacts

Cost and other detailed impacts are not required when the highest-ranking, technically feasible alternative is chosen as the BACT (EPA 1990b).

#### 4.1.4 Step 4 - Evaluation of Most Effective Control Options

Step 4 of the evaluation process takes into consideration all of the impacts derived from step 3 to arrive at the final level of control. This step validates the BACT suitability of the top control option in the control hierarchy, or provides clear justification why the top alternative is not appropriate. In some cases, the most effective option identified may result in adverse impacts to other environmental media, increases in emissions of unregulated air pollutants, or adverse energy and economic impacts. The applicant must fully document, for the public record, the rationale for rejecting the most effective options. If the top alternative is not appropriate, the next most effective control option in the control option listing becomes the new control candidate and is similarly evaluated. This process continues until the control option under review cannot be eliminated by specific environmental, energy, or economic impacts. If there are no outstanding issues regarding collateral impacts associated with the top option, then the analysis is ended and the results are proposed as BACT.

The determination that a control option is not appropriate requires a demonstration of the following:

- That conditions exist at the emission source that distinguish it from other sources
- That the control option may have been required previously
- That a sound argument can be made against the transfer of control technologies

If a control option has been applied to a limited number of sources, the applicant can identify characteristics unique to those limited sources that made the control option appropriate in those cases but not for the source under review. In the absence of unusual circumstance, it is presumed that sources in the same category are similar in nature, and the cost and other impacts borne by one source of a given category may be borne by another source of the same category (EPA 1990b).

#### 4.1.5 Step 5 - Selection of BACT

The most effective control not eliminated in previous steps is proposed as the BACT for the pollutant and emission unit under review.

#### 4.2 NO<sub>x</sub> BACT for Pretreatment Processing

The pretreatment vessel ventilation offgas treatment system consists of a counter-current caustic scrubber, high efficiency mist eliminators (HEMEs), followed by HEPA filters, a thermal oxidizer, and a carbon bed adsorber (see also section 2.2.11). The system is designed to remove solid particulates, liquid droplets, and mists from the gas stream before it is vented to the atmosphere through the pretreatment stack.

It is anticipated that there will be a minimal amount of NO<sub>x</sub> emissions generated from pretreatment vessels where high gamma activity solutions containing nitric acid result in the radiolytic decomposition of nitric acid forming NO<sub>2</sub> vapors. NO<sub>2</sub> is preferentially formed rather than NO because the source results from the reaction of nitric acid (HNO<sub>3</sub>), which is already in the higher oxidation state. This occurs in the cesium nitric acid recovery process system. An evaluation of the potential emissions has been made, and calculations show that the maximum unabated potential NO<sub>x</sub> emission rate is 0.66 US tons per year (24590-PTF-MKC-PVP-00001). The caustic scrubber has the capacity to remove approximately 33% of the NO<sub>x</sub> present in the vapor stream as presented in 24590-WTP-MRQ-PO-03-002, *Emissions Maximum Case runs with Updated Parameters*. The maximum abated emission potential is estimated to be 0.44 US tons per year. In addition, the system will be operated in such a way that will minimize the long term storage of cesium-bearing nitric acid solutions in order to prevent the generation of NO<sub>2</sub> emissions. This operational practice and the use of the caustic scrubber for removal of NO<sub>2</sub> are presented as the BACT for minimizing the very minor emissions of NO<sub>x</sub> expected from pretreatment operations.

A simplified block flow diagram of the proposed pretreatment offgas treatment system is presented in Figures 2-2, 2-3, and 2-6 of this application.

#### 4.3 NO<sub>x</sub> BACT for LAW Vitrification Processing

It has been calculated that the WTP will have the potential to generate 881 US tons per year of NO<sub>x</sub> during the LAW vitrification process (24590-WTP-RPT-MRQ-PO-03-002). The LAW process offgas containing NO<sub>x</sub> will be routed through the extensive LAW vitrification offgas treatment system, which will also treat the gas streams collected from the LAW vitrification vessel ventilation treatment system. During LAW vitrification processes, the operation of the LAW melters will form gases resulting from decomposition, oxidation, and evaporation of feed material. Most NO<sub>x</sub> emissions (primarily NO and NO<sub>2</sub>) are generated by the decomposition of feed nitrates and nitrites in the LAW melter. Within the melter, the high temperature will cause the nitrate and the nitrite in the feed to break down. Some of the compounds will be converted to NO<sub>x</sub>. Test data (Stegen 1991) shows that 50 % to 75 % of the nitrate is converted to NO<sub>x</sub>, with 25 % to 50 % converted to nitrogen, in addition to other chemical reactions that are known to occur which convert nitrates and nitrites to other compounds (Baide 1992).

The LAW vitrification plant will utilize the most effective NO<sub>x</sub> emission controls. The melter offgas will first pass through an SBS. The NO and NO<sub>2</sub> components are then treated in an SCR system, resulting in formation of inert nitrogen. The small amount of NO<sub>2</sub> remaining in the gas stream will be further reduced by a caustic scrubber downstream from the SCR system. A simplified block flow diagram of the proposed LAW vitrification offgas treatment system is presented in Figures 2-4 and 2-7 of this application.

The following sections present the BACT analysis for the control of NO<sub>x</sub> emissions from LAW vitrification processing.

#### **4.3.1 Identification of Control Technology Options**

In general, NO<sub>x</sub> emissions are limited either by control of the chemical processes to minimize or prevent the formation of NO<sub>x</sub>, or by removal of NO<sub>x</sub> from the process offgases. The major sources of man-made NO<sub>x</sub> emissions are high temperature combustion processes, such as those occurring in automobiles and power plants as identified in EPA-Office of Air and Radiation OAR Publication, 1997 National Air Quality Trends, USEPA December 1998 (EPA 1998a). For that reason, most of the technologies developed to control NO<sub>x</sub> emissions are applicable to combustion processes. Many of the technologies that are oriented toward reduction of NO<sub>x</sub> formation in combustion, such as staged combustion or low-NO<sub>x</sub> burners, are not applicable to the LAW vitrification process train. However, NO<sub>x</sub> abatement techniques that remove or transform NO<sub>x</sub> in a combustion gas stream may be applied to the LAW vitrification offgas treatment.

The NO<sub>x</sub> gas abatement technologies can be divided into 2 separate categories: wet and dry technologies. Wet methods entail absorption of NO<sub>x</sub> into an aqueous solution using different types of scrubbers. Dry NO<sub>x</sub> treatment methods do not require a liquid scrubbing medium. The following is a list of available wet and dry methods:

##### **Wet Methods (Scrubber Technologies) for NO<sub>x</sub> Abatement**

- Water scrubber
- Oxidation-adsorption with a caustic scrubber
- Absorption-oxidation
- Oxidation-complexation and absorption
- Permanganate solution absorption

##### **Dry Methods for NO<sub>x</sub> Abatement**

- Selective catalytic reduction (SCR)
- Selective noncatalytic reduction (SNCR)
- SCONO<sub>x</sub> catalytic adsorption (SCONO<sub>x</sub>)
- Nonselective catalytic reduction (NCR)
- Electron beam radiation
- Molecular sieve adsorption
- NO<sub>x</sub>SO

#### **4.3.1.1 Description of Wet Methods for NO<sub>x</sub> Abatement**

In wet treatment, offgas is passed through an aqueous solution, and NO<sub>x</sub> is absorbed into the liquid. The amount of NO<sub>x</sub> that can be removed from the offgas is dependent on the NO<sub>x</sub> concentration in the gas, the nitrogen oxide (NO) to NO<sub>2</sub> ratio (NO/NO<sub>2</sub>), the efficiency of gas-liquid contacting, and the basic chemistry of the aqueous adsorption. High NO<sub>x</sub> concentrations and low NO/NO<sub>2</sub> ratios in the gas phase

are conducive to high NO<sub>x</sub> removal efficiencies by wet adsorption. The major wet processes may be classified as simple water scrubber, oxidation-absorption with a caustic scrubber, absorption-oxidation, and oxidation-complexation. Wet scrubbers commonly remove SO<sub>2</sub> gases in addition to NO<sub>x</sub>.

NO<sub>x</sub> in the LAW melter off-gas is primarily in the form of NO and NO<sub>2</sub> (Baide 1992). NO<sub>2</sub> is readily absorbed into water, however, very little NO can be absorbed in water. To increase the amount of NO<sub>x</sub> that is absorbed into an aqueous solution, NO can be oxidized to NO<sub>2</sub>, which then can be readily absorbed into the scrubbing liquid. In the oxidation-absorption process, the NO is first oxidized with a gaseous agent and then absorbed. In the absorption-oxidation process, the NO is absorbed in a solution containing a liquid phase oxidizing agent. The oxidation-complexation process adds a chelating compound to the scrubbing solution to act as a catalyst in the absorption of NO. In each process, the resulting liquid must be treated as a wastewater prior to disposal.

Wet scrubbing technologies can be used to reduce the NO<sub>x</sub> emissions from LAW vitrification offgases, with proper engineering and application of chemistry to enhance the absorption process and removal. Efficiencies ranging from 50 % to 90 % can be achieved; Table 4-1 summarizes the performance descriptions of some wet NO<sub>x</sub> abatement technologies used commercially in Japan (Baide 1992).

#### **4.3.1.1.1 Water Scrubber**

The maximum expected removal efficiency for gaseous NO<sub>2</sub> at low concentrations (less than [ $<$ ] or equal to [ $=$ ] 1000ppmv) has been projected at 60 % with a water scrubber (Baide 1992). This estimate was made for a non-recycled water scrubber and a gas in which all of the NO<sub>x</sub> was NO<sub>2</sub>. The NO/NO<sub>2</sub> ratio in the offgas is dependent on the redox potential of a process. In the absence of organic feed reductants, NO<sub>2</sub> will make up most of the NO<sub>x</sub>. As the organic carbon loading of the melter feed increases, the potential for NO emissions increases.

#### **4.3.1.1.2 Oxidation-Absorption with a Caustic Scrubber**

To overcome the low NO<sub>x</sub> removal efficiency due to high NO/NO<sub>2</sub> ratio, NO can be converted to the readily absorbed NO<sub>2</sub>. Ozone (O<sub>3</sub>) or chlorine dioxide (ClO<sub>2</sub>) is injected into the gas stream in order to act as the oxidizing agents converting NO to NO<sub>2</sub>. In many cases, these systems were developed as modifications of commercially available flue gas desulfurization (FGD) technology. A 90 % removal efficiency has been reported with an O<sub>3</sub> to NO (O<sub>3</sub>/NO) molar ratio of 1.7 (EPA 1979). This system produces a 10 % nitric acid solution and a small amount of ozone as secondary waste products from this process. The capital and operating costs for these cleanup systems are reported to be higher than for a comparable SCR system.

A process developed by Sumitoma-Fujikasui (Baide 1992) uses chlorine dioxide as the oxidant and sodium hydroxide (caustic) as the liquid absorbent. This process reports a removal efficiency of 80 % to 90 % for NO<sub>x</sub> (and sulfur oxides [SO<sub>x</sub>]). This system consumes large amounts of caustic and produces a secondary waste stream containing sodium chloride, nitrate, and sulfate that must be treated before disposal. Most of the spent scrubbing solution is removed and recycled to the absorber after makeup caustic is added. The remaining portion of the solution, containing high levels of sodium salts, is mixed with the purge stream from the pre-scrubber. This liquid effluent and the liquid waste from the ClO<sub>2</sub> generating system are sent first to an oxidation reactor, and then to an indirect steam heater to concentrate the solution. This solution is then disposed as a liquid waste, or is evaporated in a steam heater to recover the mixed sodium salts as solids.

The primary purpose of the caustic in this process is to aid in the removal of  $\text{SO}_x$ ; however, it may also aid in the removal of  $\text{NO}_x$ . The actual sequence of all the  $\text{NO}_x$  reactions occurring in the scrubbing solution are complex. The advantage of this process is that the  $\text{NO}_x$  removal can be achieved by simply adding equipment to an existing  $\text{SO}_x$  wet scrubbing system installed in a fossil fuel power plant.

Oxidation-absorption processes generally have moderate NO removal efficiencies (80 % to 90 %) and are relatively insensitive to offgas composition. The equipment requirements are similar to a conventional FGD system with the addition of a gas phase oxidant system, and perhaps a catalyst in the scrubbing solution. The oxidation-absorption technology has 2 serious drawbacks. The first is the need for a gas phase oxidant, which is costly and corrosive to equipment. The second disadvantage is the need for treatment of the secondary liquid waste stream.

#### 4.3.1.1.3 Absorption-Oxidation

The absorption-oxidation technique is a liquid-phase reaction which occurs between an aqueous oxidant and NO. The absorption-oxidation technique is similar to oxidation-absorption, a gas-phase reaction. The process was originally developed to treat offgases from nitric acid manufacturing plants and was later adapted to treat flue gas. The NO is absorbed into an aqueous salt solution containing a liquid oxidant, such as hydrogen peroxide ( $\text{H}_2\text{O}_2$ ), or permanganate ( $\text{MnO}_4^-$ ). The oxidizing agent converts the absorbed  $\text{NO}_x$  into nitrate ( $\text{NO}_3^-$ ) salts, which must then be removed from the wastewater stream.

The low NO solubility necessitates a much longer gas-liquid contact time than that for a gas-phase oxidant. The long contact time requires a large absorber, with high liquid-to-gas ratios of 0.11 gallons per standard cubic foot, and low superficial velocities for the gas (3 feet per second to 9 feet per second). Unlike the oxidation-absorption processes, in which a catalyst can be added, a catalyst cannot be used to increase the rate of absorption, since the catalyst activity would be destroyed by the liquid-phase oxidant. This  $\text{NO}_x$  removal process has achieved a moderate removal efficiency (85 % - 90 %).

#### 4.3.1.1.4 Oxidation-Complexation and Absorption

The fundamental chemistry that controls the aqueous  $\text{NO}_x$  absorption can be altered by adding complexing agents to the scrubbing liquid to catalyze the  $\text{NO}_x$ - $\text{H}_2\text{O}$  absorption process. Ferrous ethylene diamine tetracetic acid (Fe (II) + EDTA) has been used to increase the scrubbing efficiency for both NO and  $\text{NO}_2$ , without the use of oxidants. This technique has been demonstrated in a fossil fuel power plant with  $\text{NO}_x$  removal efficiencies of approximately 90 %.

This wet scrubbing technology requires the use of an absorber with a liquid to gas ratio and low superficial velocities for the offgas if NO is to be directly removed. The addition of an oxidation step before the absorption could significantly reduce the required size of the liquid-gas contactor.

#### 4.3.1.1.5 Permanganate Solution Absorption

There are other wet  $\text{NO}_x$  removal processes that are also based on an oxidation step, followed by an absorption step. In the permanganate processes,  $\text{NO}_x$  is absorbed by a permanganate ( $\text{MnO}_4^-$ ) solution to form a  $\text{NO}_3^-$  or a nitrite ( $\text{NO}_2^-$ ), while permanganate ions are converted to manganate ions ( $\text{MnO}_4^{2-}$ ) or manganese dioxide ( $\text{MnO}_2$ ). Although over 90 % of the  $\text{NO}_x$  can be removed with the high  $\text{NO}_x$  levels found in power plant exhaust, the regeneration of the permanganate is costly. Treatment of the byproduct liquor containing the nitrate or nitrite is difficult. If the gas contains  $\text{SO}_2$ , the permanganate is consumed by the  $\text{SO}_2$ . Therefore, the flue gas must be cleansed of  $\text{SO}_2$  prior to the NO removal stage.

#### 4.3.1.2 Dry NO<sub>x</sub> Control Methods

The dry NO<sub>x</sub> abatement techniques avoid the use of a liquid scrubbing solution to capture the gaseous NO<sub>x</sub>. The SCR and selective noncatalytic reduction (SNCR) units are the major dry processes that are well developed. Both of these reduction processes inject chemicals into the gas stream that react with the NO<sub>x</sub> to produce water vapor and molecular nitrogen. The SCONO<sub>x</sub> and NCR methods use a reducing gas in combination with a catalyst to promote the reduction of all oxidizing agents in the treated gas stream. The electron beam processes use ionizing radiation to initiate chemical reactions leading to the removal of NO<sub>x</sub>; dry adsorption utilizes a molecular sieve that removes NO<sub>x</sub> from the gas stream and converts the NO component to NO<sub>2</sub> which is scrubbed with wet processes. The NO<sub>x</sub>SO method utilizes a fluidized bed of solid sorbent to adsorb both SO<sub>x</sub> and NO<sub>x</sub> from combustion flue gas. A number of dry NO<sub>x</sub> removal processes are summarized in Table 4-2.

##### 4.3.1.2.1 Selective Catalytic Reduction

The SCR chemical process was first patented by a US company in 1959 and originally commercialized in the 1970s by German and Japanese manufacturers for the control of NO<sub>x</sub> emissions from coal-fired utility boilers. SCR was used only in conventional power plants in Japan and Europe until the late 1980s. In this dry process, ammonia selectively reacts with NO<sub>x</sub> in flue gas at elevated temperatures. The optimum temperature for the reaction of NO<sub>x</sub> and ammonia without a catalyst (SNCR) is a narrow range of 1740 °F to 1830 °F. Introduction of an appropriate noble metal, base metal, or zeolite catalyst allows the reactions to proceed at lower temperatures (450 °F to 950 °F). Particulate plugging of granular or pellet-shaped catalysts has been a serious problem for the catalysts. To deal with this problem, tubular, honeycomb, and other specially shaped catalysts and parallel flow type reactors have been developed. It is possible to attain 99 % NO<sub>x</sub> removal efficiency in a nuclear process stream containing a high level (0.5 % to 2.5 %) of NO<sub>x</sub> using SCR, when sufficient amounts of ammonia and catalyst are used.

A complete SCR system consists of an ammonia storage tank, an ammonia vaporizer, a carrier gas (air or steam) supply, an ammonia injection grid, a catalyst bed, and instrumentation and controls. The SCR has been considered to be the best way to remove NO<sub>x</sub> from fossil fuel combustion because of its simplicity and removal efficiency greater than 90 %.

Metal-based catalysts have been used extensively in NO<sub>x</sub> abatement from oxygen-depleted flue gases. These catalysts have a narrow operating temperature range limited by NH<sub>4</sub>NO<sub>3</sub> formation at low temperature ranges and by competing oxygen reactions in the high temperature range. Nevertheless, several SCR systems have been examined in nuclear process applications utilizing metal-based catalysts. SCR has been applied at the West Valley Nuclear Demonstration Project Vitrification System. This demonstration system used a zeolite catalyst and achieves a 95 % to 97 % NO<sub>x</sub> removal efficiency as identified in RPT-W375LV-TE00008, *Evaluation of Alternatives for the LAW Melter Offgas System*, which would correspond to a reduction from approximately 3000 parts per million (ppm) to less than 70 ppm. A removal efficiency of 90 % would be sufficient to meet the New York State Department of Environmental Conservation NO<sub>x</sub> release regulations (Baide 1992). Although the NO<sub>x</sub> levels are relatively high, the performance data are representative of vitrification process offgas treatment with SCR. West Valley has used a wet scrubber (absorption-oxidation type) in the past to remove NO<sub>x</sub> from the offgas. This method was found to be inadequate, achieving only about a 50 % reduction of NO<sub>x</sub>.

Several problems were encountered with early applications of SCR, which have since been solved. The problems included: plugging of the catalyst by particulates; catalyst erosion by hard particulates; catalyst poisoning by SO<sub>2</sub> and metals in the flue gas; conversion of SO<sub>2</sub> to SO<sub>3</sub>, resulting in the formation of ammonia bisulfates; and the deposition of these sulfates on the catalyst and downstream equipment.

Research and development efforts have found answers to these problems. Ammonia that is not combined with the  $\text{NO}_x$  in the exhaust can pass unreacted through the reaction chamber. This unreacted ammonia is called ammonia slip. Reducing the amount of injected ammonia so that the ammonia slip is less than 5 ppm mitigates the ammonium bisulfate formation.

The zeolite catalysts have proven to be very effective SCR catalysts in oxygen-rich environments ( $\text{O}_2 > 10\%$ ). The zeolite catalysts have been proven to be efficient in reducing both NO and  $\text{NO}_2$  emissions over a wide operating temperature range (570 °F to 1380 °F), without significant loss of performance from sulfur or iodine poisoning or from high offgas water loading.

The SCR technology for  $\text{NO}_x$  reduction has been successfully demonstrated in small, pilot, and large-scale applications under many processing conditions. SCR has been shown to be effective and versatile as well as safe. The method is effective in reducing  $\text{NO}_x$  (>90 %) over a wide range of  $\text{NO}_x$  and  $\text{O}_2$  concentrations.

#### 4.3.1.2.2 Selective Noncatalytic Reduction

The SNCR process removes  $\text{NO}_x$  by injecting ammonia into a flue gas at a temperature above 1110 °F. The reactions, which convert  $\text{NO}_x$  to  $\text{N}_2$  and water, occur without the need of a catalyst. Although the removal ratio is not as high as for SCR, SNCR is simple, less expensive, and useful for gas sources for which a high  $\text{NO}_x$  removal is not needed. All tests indicate a maximum removal efficiency of 80 % for gas temperatures between 1650 °F and 1920 °F; however, large-scale plants report considerably lower values (45 %). The use of a larger amount of ammonia gives a higher  $\text{NO}_x$  removal and a larger amount of ammonia slip. The investment cost for SNCR is roughly half of that for SCR. The  $\text{NO}_x$  removal efficiency for SNCR is roughly half that of SCR and ammonia consumption and ammonia slip is much greater.

The SNCR may give 40 % to 50 % removal efficiency with a 30 ppm to 40 ppm ammonia leakage. Use of 2 to 3 moles of ammonia per mole of  $\text{NO}_x$  may give 55 % to 60 % efficiency with a 50 % to 80 ppm ammonia leakage, which may be unacceptably high. The SNCR is the simplest method for removing  $\text{NO}_x$  from flue gas and is useful for  $\text{NO}_x$  removal up to about 50 %.

SNCR has been exclusively applied to flue gases with low ( $\text{O}_2 < 5\%$ ) oxygen concentrations. The high  $\text{O}_2$  concentration ( $\text{O}_2 = 20\%$ ) in the LAW melter offgas may cause the production of  $\text{N}_2\text{O}$  and NO and lower the  $\text{NO}_x$  removal efficiency.

#### 4.3.1.2.3 SCONO<sub>x</sub> Catalytic Absorption

The SCONO<sub>x</sub> commercial process is used to reduce emissions of  $\text{NO}_x$ , CO, VOC, and  $\text{SO}_x$  from natural gas-fired power plants. Potential combustion process applications include gas turbines, boilers, and lean-burn engines. Its use is also considered for other utility and industrial process applications.

The SCONO<sub>x</sub> system uses no ammonia in its process and produces no fine particulate (PM-2.5) emissions as ammonium nitrate or ammonium sulfate. The system can operate at temperatures anywhere from 300 °F to 700 °F and works by oxidizing CO to  $\text{CO}_2$ , NO to  $\text{NO}_2$ , and then by absorbing the  $\text{NO}_2$  onto its surface through the use of a special adsorber coating. When the catalyst becomes saturated with  $\text{NO}_x$ , it has to be regenerated by passing a dilute hydrogen regeneration gas across the surface of the catalyst in the absence of oxygen. Hydrogen reacts with the adsorbed  $\text{NO}_x$  to form nitrogen and water, which are exhausted to the atmosphere instead of  $\text{NO}_x$ . Hydrogen is produced by reforming natural gas as it is

needed, and so there is no need to import any materials to operate the system at natural gas-fired power plants. The use of a natural gas reforming system to generate hydrogen, which would then be injected into the process offgas treatment system, introduces safety risks that are not acceptable in a nuclear environment (RPT-W375LV-TE00008).

#### **4.3.1.2.4 Nonselective Catalytic Reduction**

The NCR technology uses a petroleum fuel or reducing gas in combination with a catalyst to reduce all oxidizing agents in the exhaust stream. Removal efficiencies as high as 70 % have been reported and a  $\text{NO}_x$  removal efficiency of 40 % is average. Since oxygen is preferentially consumed by the nonselective method, all process oxygen has to be eliminated before  $\text{NO}_x$  can be reduced. The exothermic nature of the combustion process can cause the catalyst to burn up, which limits the NCR technology to gas streams with less than a 3 % oxygen concentration. The low oxygen concentration requirement is not compatible with the LAW melter offgas composition (20 % oxygen) (Goles 1987).

#### **4.3.1.2.5 Electron Beam Radiation**

Investigations have been conducted to develop a system to use ionizing radiation for the reduction of  $\text{NO}_x$  and  $\text{SO}_2$  in the flue gas generated by fossil fuel plants. The source of the ionizing radiation is a high-energy electron beam.

Initial research on this process was conducted by Ebara Corporation in Japan in 1970. The reaction mechanism is complex. In general, the processes include ionization, the formation of excited electronic states, the transfer of excitation energy between molecules, molecular dissociation, electron capture, neutralization, and radical reactions. The flue gas is first cooled and humidified before being irradiated. The process requires a high-intensity electron beam. In the US, AVCO Everett Research Laboratory worked with Ebara and developed a process using ammonia injection. A slipstream test of the process at a power plant demonstrated an 80 %  $\text{NO}_x$  removal efficiency with a radiation dose of 1.8 mega roentgen adsorbed dose (Mrad) and an ammonia stoichiometry of about 0.9. The unreacted ammonia, known as ammonia slip, was approximately 30 ppm. Energy consumption was claimed to be not more than that of other removal processes that simultaneously remove  $\text{NO}_x$  and  $\text{SO}_x$ , but the investment cost is high. Many large electron beam generators are needed for a large-scale plant because the electron beam has a limited range. Technical concerns about this process include questions about the ability to scale up the electron accelerators for a full-scale application and the associated power requirements for the technology. This technology has not been commercialized and is in the demonstration phase.

#### **4.3.1.2.6 Molecular Sieve Adsorption**

The molecular sieve adsorption system has been used to treat  $\text{NO}_x$  from a nitric acid plant. It reduces the  $\text{NO}_x$  concentration from 1000 ppm to 50 ppm (95 % removal) by molecular sieve adsorption. The  $\text{NO}_x$  is adsorbed on the surface of the molecular sieve substrate. The adsorbed  $\text{NO}_x$  is thermally desorbed and returned to the nitric acid plant. The process appears to be useful for treating tail gas from nitric acid plants. Union Carbide developed this process. A plant utilizing this process was commissioned in 1976 and has been operating successfully since then. It treats 22,000 normal cubic meters per hour ( $\text{Nm}^3/\text{hour}$ ) of flue gas. If this system was to be applied to the LAW vitrification offgas treatment, the  $\text{NO}_x$ , after capture, could not be recycled to a nitric acid plant. Consequently, further treatment of the  $\text{NO}_x$  stream would be required.



#### 4.3.1.2.7 NO<sub>x</sub>SO

The NO<sub>x</sub>SO process is a dry flue gas treatment process that removes both SO<sub>x</sub> and NO<sub>x</sub> from a gas stream. A 90 % removal efficiency for NO<sub>x</sub> has been estimated for a proposed full-scale demonstration of the NO<sub>x</sub>SO control technology on a 5 megawatt (MW) coal power plant. The gas stream with NO<sub>x</sub> and SO<sub>x</sub> is cleaned as it passes through a fluidized bed of solid sorbent at a temperature of 250 °F. The adsorbed NO<sub>x</sub> desorbs as the sorbent is heated to 1110 °F. The sorbent is heated to this temperature by hot air in a fluidized bed. The hot air leaving the sorbent heater and containing the NO<sub>x</sub> is mixed with the combustion air fed to the coal burner. The recycled NO<sub>x</sub> suppresses the production of NO<sub>x</sub> in the coal combustor so that the concentration of NO<sub>x</sub> in the flue gas is lowered. The NO<sub>x</sub> removal efficiency was found to increase with increasing concentration of SO<sub>2</sub> in the inlet flue gas. This makes the technology well suited to applications involving the combustion of high sulfur coal.

#### 4.3.2 Elimination of Technically Infeasible Options

The "Top-Down" Best Available Control Technology Guidance Document (EPA 1990b) gives 2 key concepts as being important in determining whether an undemonstrated technology is feasible: "availability" and "applicability". Technology is considered available if there are commercial suppliers.

More general criteria must be considered in determining whether or not a technology is applicable. Transfer of an abatement technology depends on the physical and chemical characteristics of the exhaust stream under review. Significant differences in the exhaust stream of current abatement applications and the source under review are necessary for an option to be determined infeasible. For example, infeasibility of an abatement technology cannot be determined because the technology is not in use in a radiochemical facility like the WTP. An abatement technology used in the soda-lime glass process may be applicable in the treatment of the LAW melter offgas. However, a physical or chemical property of the LAW melter offgas can preclude the use of an abatement technology. For example, a technology for removing particulate matter from a liquid wastewater stream may be found not applicable for the LAW vitrification offgas cleaning system.

An unresolvable technology difficulty may also constitute a showing of technical infeasibility. In contrast, if the resolution of technical difficulties is only a matter of cost, then the abatement technology is considered technically feasible. For example, applicability of a technology cannot be discounted because fitting it into the LAW vitrification offgas treatment system would require a larger-than-planned cell size at a considerably greater cost.

The technical feasibility or infeasibility of the abatement technologies identified for the LAW melter offgas treatment is determined on the basis of unresolvable technical difficulties rather than as an incompatibility in the transfer of the technology. An abatement technology that is effective in the removal of submicron particulates outside the nuclear industry may be considered to be transferable to a nuclear facility, and hence, applicable to the treatment of the LAW vitrification offgas.

##### 4.3.2.1 WTP Radioactive Operating Environment

Unique to the nuclear industry is the hostile operating environment of intense radiation. Equipment is located behind heavy shielding walls to keep the radiation exposure to operating personnel as low as reasonably achievable. Equipment used in a radiochemical process requires special features for the installation into the heavily shielded cell. These features make it impossible for operating personnel to directly assist in the installation of a replacement. An operator using closed circuit television will most likely perform remote removal of a failed piece of equipment from a shielded location.

The feasibility of transferring a technology from a non-nuclear application to a nuclear application like the WTP without encountering unresolvable technical difficulties depends on the ability to fit the equipment with special features that will enable remote installation or replacement and removal in a shielded cell.

The transfer of a technology from a non-nuclear application to a nuclear application like the WTP requires the equipment to be fabricated with special connectors. It is preferable that high maintenance components be serviced or replaced using a bridge crane or other equipment operated by remote control, avoiding the need to move the entire piece of equipment to the decontamination cell for cleaning. The repair or replacement of the failed component can then take place after the cleaning of the equipment piece has reduced the radiation field to an acceptable level. High radiation levels may necessitate replacement of a major equipment piece rather than repair because the dose to maintenance personnel, while acceptable, is near the limits of occupational exposure. This limited maintenance capability in the WTP operating environment may present unresolved technical difficulties for some of the identified technologies. A critical step in the feasibility analysis is the determination of maintainability in a radioactive environment. If a technology requires frequent hands-on maintenance, necessitating lengthy shutdown and causing a high exposure to the operators, then the technology is deemed infeasible.

The major types of dry and wet NO<sub>x</sub> abatement processes are summarized in Table 4-3. Their advantages and disadvantages are listed. Five control options are eliminated from further consideration because they cannot be used to reduce NO<sub>x</sub> emissions from LAW offgases.

The SCONO<sub>x</sub>, NCR, electron beam radiation, molecular sieve adsorption, and NO<sub>x</sub>SO methods are infeasible because they are not applicable to the WTP process. None of these technologies has been applied to a nuclear offgas NO<sub>x</sub> reduction system. Extensive time and resource allocation would be necessary to learn how to apply these technologies to the vitrification process. The rationale to eliminate these methods is discussed below.

### **SCONO<sub>x</sub>**

SCONO<sub>x</sub> is not applicable for treatment of offgases in the WTP facility because it relies upon the use of natural gas reforming to form hydrogen required for catalyst regeneration. Introduction of hydrogen to the nuclear process offgas stream introduces an unacceptable safety risk that eliminates application of the technology from further consideration (RPT-W375LV-TE00008).

### **NCR**

The NCR process requires that the oxygen content in the gas stream containing the NO<sub>x</sub> be less than 3 %. The LAW vitrification offgas has an oxygen content of approximately 20 %. The catalyst would be destroyed by a stream with an oxygen content that high. The NCR technology is not compatible with the LAW vitrification offgas reference conditions since the catalyst would be destroyed by the process stream composition.

### **Electron Beam Radiation**

Electron beam radiation technology is eliminated as infeasible because it is not available. The electron beam radiation processes that use ionizing radiation to initiate chemical reactions which lead to the removal of NO<sub>x</sub> are still in the process development stage. A full-scale demonstration has never been conducted, and the technology is not commercially available. Extended time delays and resource

penalties would be necessary to allow the research required to utilize this technology for the WTP. Electron beam radiation technology has not been demonstrated to reduce  $\text{NO}_x$  in a nuclear offgas system nor in flue gas with a varying  $\text{NO}_x$  level equivalent to that of the LAW melter offgas (100 ppm to 4000 ppm). This technology is not considered available for application.

#### **Molecular Sieve Adsorption**

The molecular sieve adsorption system captures  $\text{NO}_x$  but cannot be used to lower  $\text{NO}_x$  emissions from the WTP because a nitric acid plant is not available in the vicinity to process the liquids. The technology is used for nitric acid production plant operations, so the use of molecular sieve adsorption for  $\text{NO}_x$  control is an infeasible technology option.

#### **$\text{NO}_x\text{SO}$**

The  $\text{NO}_x\text{SO}$  process, like the adsorption system, only captures and then recycles the  $\text{NO}_x$  emissions. The  $\text{NO}_x\text{SO}$  process was developed for a coal burning system, and the recycled  $\text{NO}_x$  suppresses the creation of  $\text{NO}_x$  in the burner. Capturing and recycling the  $\text{NO}_x$  created in the WTP would not reduce  $\text{NO}_x$  production because the  $\text{NO}_x$  created in the WTP is not produced in a combustion process. The  $\text{NO}_x\text{SO}$  process is not applicable to the WTP since it would not reduce  $\text{NO}_x$  for the vitrification process.

### **4.3.3 Ranking of Remaining Control Technologies by Control Efficiency**

As presented in section 4.3.2,  $\text{SCONO}_x$ , NCR, electron beam radiation, molecular sieve adsorption, and  $\text{NO}_x\text{SO}$  are eliminated as technically infeasible control options. The remaining 7 control technologies include 5 wet technologies: water scrubber; oxidation-absorption; absorption-oxidation; oxidation-complexation; and permanganate solution absorption. The 2 dry methods are SCR and SNCR. These technologies are presented for ranking and further evaluation. The dry techniques for  $\text{NO}_x$  removal are generally considered superior to wet methods for the reduction of  $\text{NO}_x$  in combustion flue gas streams. Table 4-3 summarizes the advantages and disadvantages of each of the wet and dry techniques being examined. The ranking of each technology by its expected  $\text{NO}_x$  removal efficiency in treating the LAW vitrification process offgas stream is given in Table 4-4. The SCR is clearly the top ranked technology. Its maximum and expected  $\text{NO}_x$  removal efficiencies are the highest of all the feasible control technologies. SCR is the only technology proven in a nuclear application with a  $\text{NO}_x$  removal efficiency greater than 95 % and is preferred as the selected process for  $\text{NO}_x$  control.

### **4.3.4 Evaluating the Most Effective Controls**

The evaluation of control technology used for  $\text{NO}_x$  emission reduction at the WTP requires consideration of the environmental, energy, economic, and safety impacts of installing and operating the process equipment. Results of those analyses are provided in sections 4.3.4.1 through 4.3.4.5.

#### **4.3.4.1 Environmental Impact**

The major positive environmental impact of the SCR system is to reduce  $\text{NO}_x$  emissions from the WTP offgas system. The SCR could have 2 negative environmental impacts. First, the catalyst has a finite life and must be disposed of as a dangerous waste. Second, during the process operation, small amounts of unreacted ammonia are released to the atmosphere.

Typically, ammonia slip is unavoidable with the use of SCR due to imperfect mixing of the reacting gases. To obtain a high  $\text{NO}_x$  reduction efficiency from the SCR system, it may be necessary to over-

inject ammonia into the SCR reaction chamber to ensure that most of the  $\text{NO}_x$  is converted to nitrogen and water. The ammonia slip would be a secondary pollutant from the SCR system.

The other dry  $\text{NO}_x$  control system to be evaluated is SNCR. The SNCR operation will result in roughly 10 times the leakage of ammonia than the SCR, since the process is not as efficient and must be driven by higher concentrations of ammonia.

The wet scrubber technologies, water scrubber, absorption-oxidation, oxidation-complexation and absorption, oxidation-absorption with caustic scrubber, and permanganate solution absorption have similar negative environmental impacts. These technologies will generate a secondary waste stream that has to be further treated prior to disposal. Additionally, since NO is not readily absorbed into water, it has to be oxidized to  $\text{NO}_2$ . The processes entails introduction of corrosive materials such as caustic, hydrogen peroxide, or acidic complexing agents which will result in additional secondary waste for disposal. The permanganate wet process introduces an additional problem: the  $\text{SO}_2$  present in the offgas will react with the permanganate, reducing the effectiveness of this technology, consuming reagent, and forming additional wastes for disposal.

#### 4.3.4.2 Energy Impact

The major energy requirement for an SCR system for the LAW vitrification offgas treatment will be to heat the offgas upstream of the  $\text{NO}_x$  catalyst to condition inlet gases to approximately 480 °F to 570 °F entering the SCR catalyst bed to ensure efficient  $\text{NO}_x$  destruction.

Differences in the energy impact of using SCR relative to SNCR are relatively minor. The SNCR process, because of its inherently lower efficiency would have to be operated at a higher temperature to achieve significant removal efficiencies, therefore an electrical power cost to raise the offgas temperature would be incurred.

For the wet scrubber systems, adjusting the offgas temperature by indirect heat exchange or electric heaters to achieve maximum removal efficiency and solubility in scrubber liquor would be required, with the attendant increased energy usage.

A major energy impact disadvantage of oxidation-absorption with a caustic scrubber is the extensive energy requirement needed for the regeneration of the scrubbing liquid. The high energy requirements, particularly the steam needed for the evaporators, are a direct result of the required oxidation of NO to  $\text{NO}_2$  using  $\text{ClO}_2$ .

#### 4.3.4.3 Economic Impact

Cost estimates have been developed for the technically feasible control options. It will be assumed that the caustic scrubber and SBS include provisions for oxidizing NO or complexing NO/ $\text{NO}_2$  species, respectively achieving 85 % and 90 % removal efficiencies. The two scrubber systems represent the high and low end cost options for wet removal systems. It should be noted that the caustic scrubber system cost given is lower than the expected actual cost, since provisions for oxidizing NO to  $\text{NO}_2$  would be necessary and would add both to the capital and operating cost. Results are summarized in Table 4-5.

As shown in Table 4-5, the costs range from approximately \$136 to \$1,179 per US ton of  $\text{NO}_x$  removed. Therefore, the economic impact is determined to be acceptable.

#### 4.3.4.4 Safety Impact

Three main safety hazards have been identified with the use of NO<sub>x</sub> reduction technology:

- First, when ammonia is used, the handling of anhydrous ammonia could create a significant safety hazard. However, this concern can be mitigated by following Occupational, Safety and Health, EPA and industrial accepted standards and practices for handling anhydrous ammonia.
- Second, the amount of ammonia slip will increase with catalyst aging. However, ammonia slip levels are not usually considered a safety concern as long as emissions are routed to the stack, and modeled ground level concentrations are below acceptable limits.
- Third, there is a safety concern that the selected NO<sub>x</sub> reduction unit and supporting equipment may become contaminated with radioactivity and result in increased radioactive waste. However, the WTP design will remove radionuclide emissions upstream from the NO<sub>x</sub> reduction unit and reduce the potential for worker exposure to radiation.

#### 4.3.5 Selection of the Proposed Best Available Control Technology for LAW

The analysis provided in section 4.3.4 has demonstrated that SCR is the most effective NO<sub>x</sub> abatement technology for treatment of LAW melter offgas at WTP. The SCR is the NO<sub>x</sub> reduction technique with the highest removal effectiveness demonstrated in a nuclear industrial environment. NO<sub>x</sub> abatement performance ranging from 85 % to 99 % removal efficiency has been demonstrated in nuclear processing. The vitrification offgas treatment system tested at West Valley, New York has demonstrated NO<sub>x</sub> removal efficiencies of 95 % to 97 % (RPT-W375LV-TE00008).

The environmental, energy, economic, and safety impacts of applying SCR to process the LAW vitrification offgas at the WTP are determined to be manageable. A simplified block flow diagram of the proposed LAW vitrification offgas treatment system is presented in Figures 2-4 and 2-7 of this application.

#### 4.4 NO<sub>x</sub> BACT for HLW Vitrification Processing

It has been calculated that the WTP will have the potential to generate 170 US tons of NO<sub>x</sub> per year within process equipment (unabated) that is formed during the essential HLW vitrification process reactions in the melter (24590-WTP-RPT-MRQ-PO-03-002). The HLW process offgas containing NO<sub>x</sub> is passed through the extensive HLW vitrification offgas treatment system, which also treats the gas streams collected from the HLW vitrification vessel ventilation treatment system. During operation of the HLW melter, gases resulting from decomposition, oxidation, and evaporation of feed material are formed. Most NO<sub>x</sub> emissions (primarily NO and NO<sub>2</sub>) are generated by the decomposition of feed nitrates and nitrites in the melter and from chemical reactions in the process vessels. In the melter, the high temperature encountered will cause the nitrate and the nitrite in the feed to break down. Some of the compounds will be converted to NO<sub>x</sub>. Test data (Stegen 1991) shows that 50 % to 75 % of the nitrate is converted to NO<sub>x</sub> with 25 % to 50 % converted to nitrogen, in addition to other chemical reactions that are known to occur which convert nitrates and nitrites to other compounds (Baide 1992).

As evident from process flow and material and energy balance data, NO<sub>x</sub> gases are directed to the LAW vitrification offgas processing system where control of NO<sub>x</sub> emissions is done using SCR technology. Potential HLW offgas processing quantities are less than 20 % of the NO<sub>x</sub> feed to the LAW SCR. Since there is still the potential for NO<sub>x</sub> emissions from HLW processing, an SCR unit has been included in the

design. The BACT, therefore, for the HLW entails the use of SCR for NO<sub>x</sub> control. A simplified block flow diagram of the proposed HLW vitrification offgas treatment systems is presented in Figure 2-5.

Control of the NO<sub>x</sub> emissions from the HLW vitrification processes is accomplished by selection and adjustment of the feed stream materials prior to processing, by operating practices, and by process equipment design. As noted in the pretreatment discussion, addition of nitric acid to the decontamination process may also cause a potential increase in NO<sub>x</sub> emissions, so this addition is minimized in the process operations. Extensive efforts have also been made to use recycled and integrated process design approaches to minimize the excessive release of any pollutants to the atmosphere. The offgas system collects gases from both the HLW vitrification vessel vent and the HLW melter process offgas. For NO<sub>x</sub> emissions control, the most extensive pollution control measures have been incorporated into the HLW vitrification offgas treatment system. After passing through an SBS, NO/NO<sub>2</sub> components in the HLW vitrification offgases are treated in an SCR system, resulting in the formation of inert nitrogen.

The following sections present the BACT analysis for the control of NO<sub>x</sub> emissions from HLW vitrification processing.

#### **4.4.1 Identification of Control Technology Options**

The same technologies identified in section 4.3.1 for the LAW offgas treatment system for NO<sub>x</sub> emission are applicable and available for HLW offgas treatment. The technologies are also described in previous sections, as noted.

##### **Wet Methods (Scrubber Technologies) for NO<sub>x</sub> Abatement (see section 4.3.1.1)**

- Water scrubber (see section 4.3.1.1.1)
- Oxidation-adsorption with a caustic scrubber (see section 4.3.1.1.2)
- Absorption-oxidation (see section 4.3.1.1.3)
- Oxidation-complexation and absorption (see section 4.3.1.1.4)
- Permanganate solution absorption (see section 4.3.1.1.5)

##### **Dry Methods for NO<sub>x</sub> Abatement (see section 4.3.1.2)**

- SCR (see section 4.3.1.2.1)
- SNCR (see section 4.3.1.2.2)
- SCONO<sub>x</sub> catalytic adsorption (see section 4.3.1.2.3)
- NCR (see section 4.3.1.2.4)
- Electron beam radiation (see section 4.3.1.2.5)
- Molecular sieve adsorption (see section 4.3.1.2.6)
- NO<sub>x</sub>SO (see section 4.3.1.2.7)

#### **4.4.2 Elimination of Technically Infeasible Options**

As described in section 4.3.2, five options were found to be technically infeasible for LAW vitrification offgas treatment of NO<sub>x</sub> emissions, and the same reasons apply for the HLW vitrification offgas treatment applications for NO<sub>x</sub> control. The following dry methods have been eliminated as technically infeasible:

- $\text{SCONO}_x$
- NCR
- Electron beam radiation
- Molecular sieve adsorption
- $\text{NO}_x\text{SO}$

#### 4.4.3 Ranking of Remaining Control Technologies by Control Efficiency

After the elimination of 5 technically infeasible control options ( $\text{SCONO}_x$ ,  $\text{NO}_x\text{SO}$ , electron beam radiation, molecular sieve adsorption, and NCR), 7 control technologies remain for evaluation. The 5 wet technologies for evaluation are as follows:

- Water scrubber
- Oxidation-absorption
- Absorption-oxidation
- Oxidation-complexation
- Permanganate solution absorption

The 2 dry methods presented for ranking and further evaluation are as follows:

- SCR
- SNCR

The dry techniques for  $\text{NO}_x$  removal are generally considered superior to wet methods for the reduction of  $\text{NO}_x$  in combustion flue gas streams. Table 4-3 summarizes the advantages and disadvantages of each of the wet and dry techniques being examined. The ranking of each technology by its expected  $\text{NO}_x$  removal efficiency in treating the LAW vitrification offgas process stream is given in Table 4-4. The SCR is clearly the top ranked technology. Its maximum and expected  $\text{NO}_x$  removal efficiencies are the highest of all the feasible control technologies. SCR is the only technology proven in a nuclear application with a  $\text{NO}_x$  removal efficiency greater than 95 % and, therefore, SCR is preferred as the selected process for  $\text{NO}_x$  control.

#### 4.4.4 Evaluating the Most Effective Controls

The evaluation of SCR control technology used for  $\text{NO}_x$  emission reduction at the WTP requires consideration of the environmental, energy, economic, and safety impacts of installing and operating the SCR process equipment.

##### 4.4.4.1 Environmental Impact

The major positive environmental impact of the SCR system is to reduce  $\text{NO}_x$  emissions from the WTP offgas system. The SCR could have 2 negative environmental impacts. First, the catalyst has a finite life and must be disposed of as a dangerous waste. Second, during the process operation, small amounts of unreacted ammonia are released to the atmosphere.

Typically, ammonia slip is unavoidable with the use of SCR due to imperfect mixing of the reacting gases. To obtain a high  $\text{NO}_x$  reduction efficiency from the SCR system, it may be necessary to over-inject ammonia into the SCR reaction chamber to ensure that most of the  $\text{NO}_x$  is converted to nitrogen and water. The ammonia slip would be a secondary pollutant from the SCR system.

The other dry  $\text{NO}_x$  control system to be evaluated is SNCR. The SNCR operation will result in roughly 10 times the leakage of ammonia than the SCR, since the process is not as efficient and must be driven by higher concentrations of ammonia.

The wet scrubber technologies, water scrubber, absorption-oxidation, oxidation-complexation and absorption, oxidation-absorption with caustic scrubber, and permanganate solution absorption have similar negative environmental impacts. These technologies will generate a secondary waste stream that has to be further treated prior to disposal. Additionally, since NO is not readily absorbed into water, it has to be oxidized to  $\text{NO}_2$ . The processes entails introduction of corrosive materials such as caustic, hydrogen peroxide, or acidic complexing agents which will result in additional secondary waste for disposal. The permanganate wet process presents the additional problem that the  $\text{SO}_2$  present in the offgas will react with the permanganate, reducing the effectiveness of this technology, consuming reagent, and forming additional wastes for disposal.

#### 4.4.4.2 Energy Impact

The major energy requirement for an SCR system for the HLW vitrification offgas treatment will be to heat the offgas upstream of the  $\text{NO}_x$  catalyst to condition inlet gases entering the SCR catalyst bed to approximately 480 °F to 570 °F in order to ensure efficient  $\text{NO}_x$  destruction.

Differences in the energy impact of using SCR relative to SNCR are relatively minor. The SNCR process, because of its inherently lower efficiency would have to be operated at a higher temperature to achieve significant removal efficiencies; therefore, an electrical power cost to raise the offgas temperature would be incurred.

For the wet scrubber systems, it is necessary to adjust the offgas temperature by indirect heat exchange or electric heaters in order to achieve maximum removal efficiency and solubility in the scrubber liquor, with the attendant increased energy usage.

A major energy impact disadvantage of oxidation-absorption with a caustic scrubber is the extensive energy requirement needed for the regeneration of the scrubbing liquid. The high energy requirements, particularly the steam needed for the evaporators, are a direct result of the required oxidation of NO to  $\text{NO}_2$  using  $\text{ClO}_2$ .

#### 4.4.4.3 Economic Impact

Cost estimates have been developed for the technically feasible control options. It will be assumed that the caustic scrubber and the SBS include provisions for oxidizing NO or complexing NO/ $\text{NO}_2$  species, respectively achieving 85 % and 90 % removal efficiencies. The 2 scrubber systems represent the high and low end cost options for wet removal systems. (It should be noted that the caustic scrubber system cost given is lower than the expected actual cost, since provisions for oxidizing NO to  $\text{NO}_2$  would be necessary and would add both to the capital and operating cost.)

As shown in Table 4-6, the costs range from approximately \$165 to \$1,474 per US ton of  $\text{NO}_x$  removed. Therefore, the economic impact is determined to be acceptable.



#### **4.4.4.4 Safety Impact**

The safety hazards with the use of NO<sub>x</sub> reduction technologies within HLW vitrification plant are similar to that of the LAW vitrification plant (see section 4.3.4.4). In summary, 3 main safety hazards have been identified as follows:

- First, when ammonia is used, the handling of anhydrous ammonia could create a significant safety hazard. However, this concern can be mitigated by following Occupational, Safety and Health, EPA and industrial accepted standards and practices for handling anhydrous ammonia.
- Second, the amount of ammonia slip will increase with catalyst aging. However, ammonia slip levels are not usually considered a safety concern as long as emissions are routed to the stack and modeled.
- Third, there is a safety concern that the selected NO<sub>x</sub> reduction unit and supporting equipment may become contaminated with radioactivity, resulting in increased radioactive waste. However, the WTP design will remove radionuclide emissions upstream from the NO<sub>x</sub> reduction unit and reduce the potential for worker exposure to radiation.

#### **4.4.5 Selection of the Proposed Best Available Control Technology**

The SCR system has been demonstrated as the most effective NO<sub>x</sub> abatement technology for treatment of HLW melter offgas from the WTP. Its use has been integrated into the HLW vitrification offgas treatment system. SCR is the NO<sub>x</sub> reduction technique with the highest removal effectiveness demonstrated in a nuclear industrial environment. NO<sub>x</sub> abatement performance ranging from 85 % to 99 % removal efficiency has been demonstrated in nuclear processing. The vitrification offgas treatment system tested at West Valley, New York, has demonstrated NO<sub>x</sub> removal efficiencies of 95 % to 97 % (RPT-W375LV-TE00008).

The environmental, energy, economic, and safety impacts of applying SCR to process the HLW vitrification offgas at the WTP are determined to be manageable. A simplified block flow diagram of the proposed HLW vitrification offgas treatment system is presented in Figures 2-5 and 2-8 of this application.

#### **4.5 NO<sub>x</sub> BACT for the Steam Boiler Plant**

Industrial boilers are to be operated in the boiler plant to provide high pressure steam for the WTP. The boilers are complete packaged units designed for automatic operation. They will emit nitrogen oxides at a rate significantly below EPA's new source performance standards for fossil fuel-fired generators specified in 40 CFR 60.44, which is 0.3 pound NO<sub>x</sub> per million British thermal unit (mmBtu) heat input.

The process boiler system, which serves the WTP, consists of 6 ultra-low sulfur content (30 ppm sulfur content or 0.003% by weight), distillate fuel oil-fired, steam-generating boilers rated at 50.2 mmBtu per hour heat input for each boiler. The boilers are complete horizontal-packaged firetube boilers, and each is rated to provide 41,400 pounds per hour (lb/hr) of 135 pounds per square inch (psig) steam at approximately 360 °F for process operations per 24590-BOF-3YD-HPS-00001, *System Description of High Pressure Steam (HPS) and Steam Condensate Water Systems (SCW)*. The individual boiler units provide the necessary turn-down flexibility for process operations, depending on the feedstock being treated, and the broad range of operational and facility requirements. It is anticipated that all boilers will not be operating at the same time at full power, but they all must be available on a standby basis. Potential to emit calculations are based on 3 steam boilers operating all year long. NO<sub>x</sub> emissions will be

reduced by restricting the hours of operation of the remaining 3 steam boilers to 3,679 hours per year. Since these boilers are a part of the NO<sub>x</sub> emission source, PSD regulations require that a BACT analysis be performed. The following sections present the results of that BACT analysis. During combustion of fuel oil for the generation of high pressure steam, NO<sub>x</sub> is formed in 2 major ways:

- 1 By oxidation of nitrogen in the combustion air (referred to as thermal NO<sub>x</sub>)
- 2 By oxidation of elemental nitrogen chemically bound in the feed material (referred to as fuel NO<sub>x</sub>)

It should be noted that there is a third mechanism for combustion-NO<sub>x</sub> formation in which molecular nitrogen in the combustion air reacts with free hydrocarbon radicals available from the fuel in the combustion zone. Hydrogen cyanide is formed which subsequently combines with free hydroxyl radicals to form cyanide, which is then oxidized to NO through a number of intermediate steps. This is called "prompt NO" that forms under combustion conditions with little sensitivity to temperature or other operating conditions. The contribution to overall NO<sub>x</sub> formation from "prompt NO" is relatively small and will not be considered further in this BACT discussion.

Experimental measurements of thermal NO<sub>x</sub> formation have shown that NO<sub>x</sub> concentration is exponentially dependent on temperature, and proportional to the following conditions: N<sub>2</sub> in the flame; the square root of O<sub>2</sub> concentration in the flame; and the residence time. Thus, the formation of thermal NO<sub>x</sub> is affected by 4 factors: 1) peak temperature, 2) fuel nitrogen concentration, 3) oxygen concentration, and 4) the time of exposure at peak temperature. The emission trends, due to changes in these factors, are generally consistent for all types of boilers: an increase in flame temperature; fuel-bound nitrogen concentration; oxygen availability; and residence time at high temperatures. These conditions can lead to an increase in NO<sub>x</sub> production.

Fuel-bound nitrogen conversion is a major NO<sub>x</sub> forming mechanism in boilers firing heavy residual oil. The percent conversion of fuel nitrogen to NO<sub>x</sub> varies greatly, however typically from 20 % to 90 % of nitrogen in oil is converted to NO<sub>x</sub>. Except in certain large units which have unusually high peak flame temperatures (thereby generating high concentrations of thermal NO<sub>x</sub>) or which have units firing a low fuel-bound nitrogen content residual oil, fuel NO<sub>x</sub> accounts for 50 % or more of the total NO<sub>x</sub> generated. Thermal fixation, on the other hand, is a more significant NO<sub>x</sub>-forming mechanism in units firing lighter distillate oils, primarily because of the lower nitrogen content in these lighter oils, although this may vary significantly depending on the source of the fuel oil. Distillate oil-fired boilers are usually smaller and have lower heat release rates than residual fuel boilers. NO<sub>x</sub> emissions for distillate fuel-fired boilers (per unit of fuel burned or heat released) from both fuel-bound and thermal NO<sub>x</sub> formed is generally less than that of larger units which typically burn residual oil.

#### **4.5.1 Identification of Control Technology Options**

Strategies for control of NO<sub>x</sub> emissions from combustion processes can be separated into 2 categories: 1) combustion process control technologies, which have been demonstrated in practice, and 2) post-combustion reduction technologies, considered transferable as possible NO<sub>x</sub> control systems for small packaged boilers. These are summarized in the following list:

##### **Techniques of Combustion Process Control of NO<sub>x</sub> Emissions**

- Burners out of service (BOOS)
- Reduced air preheat (RAP)
- Oil/water emulsified fuel (O/W EF)

- Load reduction (LR)
- Low excess air (LEA)
- Staged combustion (SC)
- Low-NO<sub>x</sub> burners (LNBs)
- Flue gas recirculation (FGR)
- FGR plus staged combustion/LNBs (FGR and LNBs)
- LNB with Steam Atomization

#### **Post-combustion NO<sub>x</sub> Reduction Technologies**

- SNCR
- SCR

Table 4-7 provides a brief description, ranking, and applicability discussion for control techniques grouped as combustion control or post-combustion control technologies.

#### **4.5.1.1 Description of Techniques of Combustion Process Control of NO<sub>x</sub> Emissions**

Combustion controls are the most widely used method of mitigating NO<sub>x</sub> formation in all types of boilers, and include:

- Burners out of service (BOOS)
- Reduced air preheat (RAP)
- Oil/water emulsified fuel (O/W E)
- Load reduction (LR)
- Low excess air (LEA)
- Staged combustion (SC)
- Low-NO<sub>x</sub> burners (LNBs)
- Flue gas recirculation (FGR)
- FGR combined with staged combustion/LNBs (FGR and LNBs)
- LNB with Steam Atomization

The following summary is general and is intended to provide a broad overview of these technologies:

##### **BOOS**

The BOOS involves withholding fuel flow to all or part of the top row of burners so that only air is allowed to pass through. This method simulates air staging, or overfire air conditions, and limits NO<sub>x</sub> formation by limiting the amount of oxygen in the firing zone.

##### **RAP**

The RAP entails bypass of the combustion air preheater to reduce combustion air temperatures to ambient conditions in an attempt to minimize flame temperature and the associated formation of thermal NO<sub>x</sub>.

### O/W EF

The fuel alteration for reduced NO<sub>x</sub> generation includes use of O/E WFs. The EPA has conducted tests with commercially premixed No. 6 residual oil and water containing a petroleum based emulsifying agent in a firetube boiler. It was determined that a NO<sub>x</sub> reduction potential of approximately 40 % was achieved. This was attributed to improved atomization with a corresponding reduction of excess combustion air, with lower flame temperature contributing slightly to the reduction. No results with distillate fuels were available. However, similar reduction in NO<sub>x</sub> emissions may be attainable through O/W EF technique.

### LR

The LR is accomplished by reducing air and fuel flow to all burners in service and is dependent on boiler design and excess air requirements. It is associated with retrofit modification of existing boiler systems.

### LEA

Operating at LEA involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NO<sub>x</sub> formation is inhibited because less oxygen is available in the combustion zone.

### SC

The SC (also known as off-stoichiometric combustion) breaks the process down into 2 or more steps or stages. The first step is to carry out combustion in a fuel-rich zone, and each subsequent step is known as fuel-lean operation. Fuel-lean operation in some boiler designs is accomplished by adding overfire air in which a percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. Overfire air limits NO<sub>x</sub> emissions by suppressing thermal NO<sub>x</sub> production by partially delaying and extending the combustion process, which results in less intense combustion and cooler flame temperatures. By reducing flame temperature and residence time at peak temperature, NO<sub>x</sub> formation is reduced. The SC method requires careful monitoring to keep CO and smoke concentrations to a minimum.

### LNBs

The LNBs reduce the formation of thermal NO<sub>x</sub> in the flame zone of a boiler or incinerator utilizing LEA and SC principles. Within the flame, the amount of oxygen available for reaction with nitrogen is minimized, and the temperature, which is the driving force for the reactions of nitrogen with oxygen, is also reduced and controlled. The LNBs accomplish NO<sub>x</sub> control by staging combustion within the flame of a burner. This involves a number of different proprietary mechanisms to effect turbulence within the flame zone, modifying the shape of the flame, reducing the velocity of the fuel as it is injected, recirculating combustion gases within the flame zone, staging the introduction of oxygen into the burner flame zone, and any combination of these techniques. The LNBs have been used as a retrofit NO<sub>x</sub> control for existing boilers and can achieve 20 % to 50 % reduction from uncontrolled levels. LNBs can be combined with overfire air to achieve even greater NO<sub>x</sub> reduction (40 % to 60 % reduction from uncontrolled levels).

## **FGR**

The flue gas recirculation involves extracting a portion of the flue gas from the economizer section or air heater outlet and readmitting it to the furnace through the furnace hopper, the burner windbox, or both. Because of the potentially significant modifications to equipment including ductwork, fans, dampers, heat recovery, and controls, FGR is more appropriate for new designs rather than for retrofitting. This method reduces the concentration of oxygen in the combustion zone and may reduce NO<sub>x</sub> by as much as 60 % to 70 % from uncontrolled levels.

## **FGR and LNB**

The FGR and LNBs combine the application of FGR and low NO<sub>x</sub> burner technology, usually in a packaged boiler design. Some constraints may be made on operational flexibility, such as turndown, because possible flame instabilities may result as fuel firing rates are decreased, and because the stable range of flue gas recirculation rate operating points may be more limited than would exist in an uncontrolled unit. A nominal NO<sub>x</sub> reduction up to approximately 75 % of uncontrolled NO<sub>x</sub> levels may be achieved.

All these methods require careful monitoring to keep CO and smoke concentrations down. Each method may change the normal operation of a boiler, and the effectiveness of each is boiler-specific. Implementation of the techniques may also reduce operational flexibility; however, they have the potential to reduce NO<sub>x</sub> by ranges up to 75 % relative to uncontrolled levels, depending on the fuel and boiler type or size.

Demonstrated technologies for steam generation are based on feed and combustion control. By controlling the fuel bound nitrogen content and combustion process, it is possible to minimize the quantities of NO<sub>x</sub> formed. Combustion process controls are a form of avoidance of formation of NO<sub>x</sub>. Use of LNBs, flue gas recirculation, and other combustion controls to minimize NO<sub>x</sub> formation has become a standard practice in the combustion equipment design and manufacturing industry for a wide range of combustion applications.

## **LNB with Steam Atomization**

Steam atomization is a method of attaining proper oil droplet size for efficient fuel oil combustion. The steam atomization and fuel oil boiler are designed to reduce thermal NO<sub>x</sub> generation rates. The Cleaver-Brooks boiler design is a fire-tube wet back type with a burner arrangement utilizing leverless direct servo motors for superior combustion and NO<sub>x</sub> reduction control. The steam added as part of the burner design absorbs heat from the flame, cooling the peak flame temperature, and reducing thermal NO<sub>x</sub> (Niepow 2003). Steam atomization operates on the same principle as flue gas recirculation, i.e. reducing thermal NO<sub>x</sub> generation by reducing flame temperatures.

The Cleaver-Brooks boiler design is not commercially available with FGR. The combination of FGR with this boiler design has not been attempted. However, since steam atomization is a similar technology to FGR for NO<sub>x</sub> reduction, there is no significant additional NO<sub>x</sub> reduction with the addition of FGR. In fact, it is possible the increased flame cooling provided by FGR may lead to flame instability and increased CO emissions (Niepow 2003).

The NO<sub>x</sub> emission factor for the previously proposed system (LNB with FGR) was 0.187 lb/MMBtu. The NO<sub>x</sub> emission factor for the proposed Cleaver-Brooks design with steam atomization is 0.09 lb/MMBtu. It is obvious from the lower emission factor that steam atomization provides superior NO<sub>x</sub> control than

LNB and FGR. Table 4-8 provides the results of an EPA RACT/BACT/LAER Clearinghouse query for commercial, institutional boilers less than 100 mmBtu/hr. The WTP proposed emission rates (0.09 lb/MMBtu/hr, 4.68 lbs/hr at 100% firing rate) are lower than the emission rates for the sources identified in Table 4-8, with 1 exception.

#### **4.5.1.2 Description of Post-Combustion NO<sub>x</sub> Reduction Technologies**

Post-combustion technologies used for NO<sub>x</sub> reduction in combustion of fuel oil include the use of various kinds of SNCR and SCR systems.

The SNCR is a post-combustion technique that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with the NO<sub>x</sub> in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected, mixing of the reagent in the flue gas, residence time of reagent within the required temperature window, ratio of reagent to NO<sub>x</sub>, and the sulfur content of the fuel that may create sulfur compound deposits in downstream equipment. There is limited commercial experience on a wide range of boiler types, however; in limited applications, NO<sub>x</sub> reductions ranging from 40 % to 70 % have been achieved.

The SCR is another postcombustion technique that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO<sub>x</sub> to nitrogen and water. The SCR reactor can be located at various positions in the process, including before an air heater and particulate control device, or downstream of the air heater, particulate control device, and flue gas desulfurization systems. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, fuel contaminant content, ammonia-to-NO<sub>x</sub> ratio, inlet NO<sub>x</sub> concentration, space velocity, and catalyst condition. NO<sub>x</sub> emission reductions of 90 % have been achieved through the use of SCR on large oil-fired boilers operating in the US.

As part of the BACT review, an online search of the Reasonably Available Control Technology (RACT)/BACT/LAER clearinghouse (EPA 2003a) indicated that neither SCR nor SNCR has been applied to small firetube boilers for steam generation using low fuel-nitrogen distillate liquid fuels comparable to those required for the WTP steam boiler plant. In those cases where NO<sub>x</sub> controls were used, the method of control chosen was some type of combustion control.

The selective NO<sub>x</sub> reduction process, however, represents a potentially transferable technology. Selective NO<sub>x</sub> reduction can be achieved through catalytic and non-catalytic processes. Research indicates that these technologies have been successfully applied to other combustion processes; therefore, these technologies were evaluated for potential application to the WTP.

#### **4.5.1.3 Evaluation of Demonstrated Technologies**

##### **4.5.1.3.1 Combustion Controls (General)**

The BOOS, RAP, O/W EF, LR, LEA, and SC technologies are either for retrofit only, are not demonstrated, or do not offer sufficient benefit for NO<sub>x</sub> emission control for distillate fired boilers to be discussed further. Therefore, the subsequent discussion will focus on the highest ranked combustion control technologies, including FGR and LNBs, and their combination.

LNBs and flue gas recirculation are sometimes considered together to be a subset of combustion controls and sometimes considered individually to be separate control options. For the purposes of this BACT

analysis, LNBs and flue gas recirculation will be dealt with as separate control options, with the third option being the combination of both in a packaged system.

All combustion controls have the inherent advantage of controlling NO<sub>x</sub> emissions at the source rather than being add-on control systems. This is preferred in the hierarchy of pollution prevention planning. The reduction of NO<sub>x</sub> using combustion controls, including combinations of NO<sub>x</sub> reduction methods, can be as high as 60 % to 75 % of uncontrolled emissions, depending on the type of controls used and the type of fuel being burned. In addition, these controls cause no ammonia releases and do not generate hazardous waste. Also, there is no need for additional chemicals, so there is no risk associated with chemical accidents while storing or handling chemicals.

Technical disadvantages of the combustion control NO<sub>x</sub> reduction technologies are the potential for limited operating flexibility, such as limiting the range of stable firing levels or turndown of the boiler and the potential for reduced thermal/combustion performance efficiency.

#### **4.5.1.3.2 Low-NO<sub>x</sub> Burners**

LNBs reduce the formation of thermal NO<sub>x</sub> in the flame zone of a boiler. Within the flame, the amount of oxygen available for reaction with nitrogen is minimized, and the temperature, which is the driving force for the reactions of nitrogen with oxygen, is also reduced and controlled. Low-NO<sub>x</sub> burners accomplish NO<sub>x</sub> control by staging combustion within the flame of a burner. This involves a number of different proprietary burner design configurations to affect turbulence within the flame zone, modifying the shape of the flame, reducing the velocity of the fuel as it is injected, recirculating combustion gases within the flame zone, staging the introduction of oxygen into the burner flame zone, and any combination of these techniques. LNBs are most effective when applied in a new boiler design that is tailored to the modified flame zone characteristics typical of the technology.

The primary advantage of LNBs is their ability to achieve significant NO<sub>x</sub> reductions at a relatively modest cost. LNBs can also be combined with other NO<sub>x</sub> control technologies, such as flue gas recirculation or other combustion control techniques in order to achieve greater combined NO<sub>x</sub> control than the individual technologies are capable of achieving. LNBs also require a minimal amount of maintenance, as do all combustion control technologies.

LNBs reduce thermal NO<sub>x</sub> formation by reducing flame temperatures and available oxygen in the burner flame zone. Unless proven process design equipment is used in order to restrict the effects of reduced flame temperatures and oxygen concentrations that reduce NO<sub>x</sub> formation, they may adversely affect thermal or combustion efficiencies.

#### **4.5.1.3.3 Flue Gas Recirculation**

FGR, like low-NO<sub>x</sub> burners technology, is best applied in new burner design systems rather than in retrofit applications. FGR is routinely used with and without LNBs in the package boiler industry as NO<sub>x</sub> control technology. Depending on the application and vendor design, the exhaust gas recirculation may be external, routing gases from ducts external to the boiler or inducing recirculation of flue gas internal to the boiler using the combustion air blower. This effectively limits the formation of NO<sub>x</sub> by reducing the oxygen concentration and effectively lowering the flame temperature.

As in other combustion control techniques, FGR is used to limit NO<sub>x</sub> at the source and is therefore a preferred method from a pollution prevention standpoint, as are LNBs. New boiler designs with integral

FGR technology have the advantages of simplicity and reliability that have been proven in industrial service.

Flame impingement on boiler water tubes have reportedly caused reliability problems and have raised questions about the long-term performance of some flue gas recirculation systems. Also, proper design is needed to ensure complete combustion of CO to CO<sub>2</sub> and combustion flame stability, particularly for turndown or off-base load firing.

#### **4.5.1.3.4 Flue Gas Recirculation and Low-NO<sub>x</sub> Burners**

The combination of FGR and LNB is commonly practiced in the package boiler industry, and proven system designs are commercially available.

The maximum benefits of both FGR and LNB technology can be fully utilized to minimize the formation of NO<sub>x</sub>. The system can be selected to provide the operating flexibility required while offering the maximum potential for NO<sub>x</sub> control.

The combination of FGR and LNBs may not be feasible in retrofit applications. Also, turndown of boiler firing rates may be limited, and CO emissions may be increased relative to a boiler with no NO<sub>x</sub> controls.

#### **4.5.1.4 Evaluation of Transferable Technologies**

The SNCR and SCR have been identified as a potentially transferable technologies. These technologies have been successfully used in other combustion processes. The following discussion presents both selective noncatalytic and SCR technology.

##### **4.5.1.4.1 Selective Noncatalytic Reduction**

For the SNCR, ammonia is reacted with NO<sub>x</sub> to convert it to diatomic nitrogen and water vapor. Since SNCR does not use a catalyst, it must be operated at a relatively high temperature, typically between 1600 °F and 2100 °F, to accomplish the needed chemical reaction. Strict temperature control within this range is required for proper operation of the process. Below the minimum temperature, NO<sub>x</sub> conversion will fall off rapidly, resulting in excessive ammonia releases. Above 2000 °F, the process will convert the ammonia to NO<sub>x</sub>, resulting in even higher concentrations of NO<sub>x</sub>.

Because of the lack of the catalytic impetus for the reaction, use of SNCR technology requires a greater feed quantity of ammonia to accomplish the reduction than is required when using a catalyst. Ammonia ratios as high as 1.6 to 2.5 times the amount required for stoichiometric conversion of NO<sub>x</sub> have been required in some applications. In contrast, ratios less than 1 are used for SCR. Therefore, higher ammonia emission rates can result from using SNCR technology relative to SCR.

SNCR has been principally applied to large boiler and process heater applications (more than 10 times the size of the process boilers required for the WTP) firing residual or some alternative fuels. The use of SNCR on boilers and process heaters with thermal loads and fuel properties requiring postcombustion control is moderately effective, achieving a reduction of 40 % to 70 % of NO<sub>x</sub> emissions.

Large residual oil- and miscellaneous fuel-fired boilers have been adapted to SNCR technology where the firebox and flue geometry are amenable to modification. Also, flue gas temperatures have to be sufficiently high, that is between 1600 °F to 2100 °F. The hot side of a firetube boiler is typically in the range of 500 °F to 600 °F, which is well below the necessary operating inlet temperature for an SNCR



system. An extensive reheat system would have to be designed and constructed just to establish the necessary inlet temperature for the process. Successful applications of SNCR have been made in systems significantly larger than the WTP boilers. Because there is a lack of experience using SNCR on small firetube boilers burning relatively low fuel-bound nitrogen distillate fuel, the quantitative  $\text{NO}_x$  reduction performance is not known. The actual value of this technology cannot be accurately assessed, although it can be expected to be far less effective than for the facilities where the technology has been applied.

The SNCR will reduce  $\text{NO}_x$  emissions. However, the quantitative level of  $\text{NO}_x$  reduction is cannot be accurately estimated for a small distillate fuel boiler.

In addition to extensive redesign and fabrication, changes would be required to meet process inlet temperature requirements, elaborate reagent injection, and monitoring and control modifications on the boiler system. Any problems with incomplete mixing, insufficient residence time, or temperature control may result in increased NO or ammonia ( $\text{NH}_3$ ) emissions.

Another environmental disadvantage to using SNCR is the increase of carbon monoxide emissions at the operating temperatures (1600 °F to 2100 °F) required for the process. In addition, the presence of high levels of the reducing agent,  $\text{NH}_3$ , prevents further oxidation of carbon monoxide to carbon dioxide. Although the exact increase is unknown due to the lack of operational experience, even a small incremental increase of 10 % would have a negative impact.

The SNCR would also require additional energy for temperature control and reheat, ammonia vaporization and sweep gas, depending on design modification requirements. This energy requirement can be up to hundreds of millions of Btu per year.

Finally, the potential  $\text{NO}_x$  reduction of SNCR is less than that of successfully applied combustion control (40 % to 70 % versus 60 % to 75 % for FGR and LNB). Given all the other disadvantages of SNCR, this is sufficient to disqualify the technology for the WTP steam boiler plant.

#### 4.5.1.4.2 Selective Catalytic Reduction

In SCR, ammonia gas is reacted with  $\text{NO}_x$  in the presence of a catalyst to form diatomic nitrogen gas and water vapor. The process takes place inside a reactor and requires that the ammonia be evenly distributed throughout the gas flow. To accomplish this, an injection grid is used, which injects precisely controlled amounts of ammonia through a bank of numerous small nozzles. The ammonia is then mixed into the flow with baffles and gas flow distributors, if needed, to provide a uniform flow through the catalyst bed, which can be a packed bed or monolithic honeycomb-type system. (Originally, this process required a very narrow temperature band, but improvements have now made it possible to operate within a range from 600 °F to 800 °F). However, the temperature band must be strictly maintained. Below this temperature, the catalyst activity is too low; and above this temperature, the catalyst can be damaged by sintering, or the process may actually form additional  $\text{NO}_x$  or other undesirable byproducts.

A fixed-bed catalyst using a honeycomb structure is the most common form of catalyst. Typically, the catalyst will contain titanium oxide, vanadium pentoxide, and tungsten oxide in proportions tailored to fit the particular gas stream. These catalysts are filled with macro- and micro-pores resulting in a very large surface area for a given volume. In operation, the gas stream flows through the catalytic reactor, which may contain 2 to 4 catalyst beds, in series. In the catalyst beds, the ammonia and  $\text{NO}_x$  diffuse into the pores and react at a catalytic site.

SCR can be applied in 2 basic process locations:

- 1 before treatment of the offgas (before the heat is removed, referred to as hot side SCR)
- 2 after air pollution abatement treatment (post-air pollution abatement SCR)

In the former case, heat from the combustion process can be used to provide the optimum temperature range required.

One disadvantage to SCR is that even small concentrations of materials present in combustion gases, such as particulates, volatilized metals, hydrochloric acid, and sulfur dioxide will rapidly deactivate the catalyst material, leading to rapid degradation of pollution abatement efficiency (Chen and Yang 1990) (Chen 1990). However, the hot side SCR would be required for liquid fuel combustion applications in order to meet inlet flue gas temperature requirements. The temperature downstream of a typical boiler economizer ranges from approximately 300 °F to 350 °F, which is below the possible operating range of an SCR system. A hot side flue gas of approximately 500 °F to 600 °F could be used for SCR feed gas.

Normally, the advantage to post-air pollution abatement SCR is that the pollution abatement system would be effective in mitigating the presence of catalyst poisons. The primary disadvantage is the significant cost for energy required to reheat the offgas to the temperature range required for SCR operation. Post-air pollution abatement SCR may be a feasible option for consideration in large utility boilers but is inappropriate for application to small firetube boilers. SCR technology has principally been applied to utility boilers and utility boilers used for power generation have very large thermal loads which result in large quantities of NO<sub>x</sub> generation, usually in excess of 250 US tons per year over a 20-year expected operating lifetime. SCR NO<sub>x</sub> control is suited to these large-scale power generation facilities because both the thermal load and the physical properties of the fuel are relatively stable. The resulting NO<sub>x</sub> concentrations are also stable.

The performance that can be achieved by SCR theoretically ranges up to a nominal value of 90 %. Proper design variables (such as temperature control, the amount of catalyst, residence time in catalyst, and the stoichiometric ratio of ammonia to NO<sub>x</sub>) are not well defined for a small application such as with small firetube boilers processing low-nitrogen content distillate fuels. Operating parameters, such as catalyst lifetime, are also not known. These unknowns interject significant uncertainty in the potential for successful application of SCR for the WTP.

The obvious benefit from the application of SCR technology is the reduction in NO<sub>x</sub> that could be obtained. Unfortunately, because of the lack of operational experience with small, low-nitrogen distillate fuel and firetube boilers, the degree of reduction and reliability is unknown. Performance with other large oil-fired boilers suggests that the NO<sub>x</sub> reduction obtained is variable (a range of 25 % to 90 %) and would be less effective in smaller distillate fuel applications that already have low NO<sub>x</sub> emissions, than in larger residual oil-fired boiler applications.

The disadvantages to SCR include additional energy consumption, additional air pollutants release, and hazardous waste generation. The impact of catalyst poisons on hot side operation is not well known and process reliability is not known. Flue gas contaminant removal by additional pollution control devices may be required and gas temperature would have to be conditioned for proper operation. Ammonia vaporization and sweep gas production would consume a small amount of additional energy. There is also an added energy cost associated with the flue gas pressure drop of 3 to 6 inches of water column through the catalyst bed. This associated energy cost will be manifested in additional NO<sub>x</sub> emissions from fuel combustion.

The emission of other air pollutants also represents a disadvantage of the use of SCR. The main concern with additional air pollutants is from the ammonia used in this technology. The formation and release of  $\text{NO}_x$  over time during combustion will be variable. This will, in turn, require adjustment of the critical  $\text{NH}_3$ -to- $\text{NO}_x$  stoichiometric feed ratio. If the ratio is too high, it will result in the release of a significant amount of unreacted ammonia. If the ratio is too low, the  $\text{NO}_x$  removal efficiency will also be lowered.

Another negative environmental consequence of using SCR for  $\text{NO}_x$  control is associated with the volume of catalyst that must be disposed. The spent catalyst will be classified as dangerous waste requiring special handling and disposal procedures.

There would also be inherent general economic disadvantages associated with the use of SCR if it were found technically feasible. Capital costs, including the initial catalyst bed, can be significant; in conventional industrial applications, costs are amortized over 20 years (the expected operating life of these facilities) in the analyses referenced. Operating costs include ammonia usage, energy requirements, and catalyst replacement and disposal. For utility boiler applications, ammonia is typically used at a  $\text{NH}_3$ -to- $\text{NO}_x$  ratio of less than 1; catalyst lifetimes are normally projected at 4 to 6 years. If the use of SCR for the small power boilers at WTP were deemed to be technically feasible, the cost per US ton of  $\text{NO}_x$  removed from a small packaged boiler modified to be controlled by an SCR unit is difficult to estimate since designs would be experimental at best. Because catalyst life cannot be predicted due to uncertainties related to the composition of exhaust gases, and due to the fact that there are no systems in use commercially for small firetube boilers burning distillate fuel oil, SCR is not considered a technically feasible option.

#### 4.5.1.5 Evaluation of Innovative Technologies

##### 4.5.1.5.1 Catalytic Combustion of Fuel Oil

Catalytic combustion is identified as an innovative technology for potential use in reducing  $\text{NO}_x$  emissions in fossil fuel-fired systems. The technology was researched extensively in the 1980s, and tests were conducted with a number of fossil fuels, including coal gas, residual oil, natural gas, liquefied petroleum gas, and fuel oil. Development of the technology was driven by the attempt to control fuel combustion inside the channels of ceramic monolithic honeycombs coated with precious metal catalysts. Oxidation reactions were initiated and supported by the catalysts at temperatures below those where thermal  $\text{NO}_x$  are generated, that is, below adiabatic flame temperatures of 2300 °F (1260 °C). This was accomplished by operating at fuel-lean, sub-stoichiometric air/fuel ratios. Fuel oil-fired operations of catalysts for boiler applications were demonstrated at heat release rates up to 1 million Btu/hour, and  $\text{NO}_x$  emissions in the 5 ppm to 10 ppm range were achieved in short-term tests. Technical problems were associated with loss of catalyst stability and performance - more specifically, the loss of catalyst activity by poisoning, attrition, sintering, and performance failure by physical degradation of the ceramic substrate from fuel maldistribution or thermal shock. These problems were not resolved, preventing commercialization of the technology, although it was proven to work in short term, pilot plant tests. Research and development of this technology has not continued.

##### 4.5.1.5.2 Hybrid SNCR/SCR

Another innovative technology that has been applied to fuel oil boiler operation for steam generation was the retrofit of a small, 2-million British thermal unit per hour (mmBtu/hour) firetube boiler with a combined SNCR and SCR system. This pilot scale system was set up as a research project to provide for injection of urea, rather than ammonia, into the main firetube (first pass) countercurrent to the forced air

combustion gas flow. Downstream of the second-pass tubes and before the third-pass tubes of the North American package boiler, a square cell, honeycomb-type ceramic SCR catalyst bed was mounted where the access doors of the boiler normally attach. The combined application of SNCR and SCR allowed the use of a smaller catalyst volume, with lower pressure drop than would otherwise be required to meet performance levels. It was determined, using an on-line ammonia monitor, reagent flowmeter, and process controls during a 40-hour constant operation test, that 87 % NO<sub>x</sub> reduction could be achieved with an average ammonia slip of 11 ppm by volume. It was noted that further testing may be needed to assess long-term boiler effects and long-term catalyst durability, but the concept was experimentally demonstrated. Although not commercially available, the hybrid design may have more promise for future commercialization than catalytic combustion, pending development of boiler-catalyst system designs. At this level of applied complexity and technology development, however, other options, such as use of natural gas fuel to reduce NO<sub>x</sub> emissions, may prove to be more practical.

#### **4.5.1.6 Lower Polluting Options**

A lower pollution option was not analyzed for this system. Fuel-oil fired boilers were selected to safely and reliably deliver high pressure steam for the WTP in the early design phases of the project when it was decided that it presented the smallest overall risk to the public. Other options were either not feasible or not safe. The WTP system is projected to be online for a limited time as needed to treat and stabilize the waste. Potential adverse impacts from other experimental treatment options outweigh consideration of marginal reductions in emissions of NO<sub>x</sub> from the steam boilers.

#### **4.5.2 Technical Feasibility Considerations**

The combustion control techniques that are feasible include use of low-NO<sub>x</sub> burners, flue gas recirculation and their possible combination. Other combustion technologies that were discussed for NO<sub>x</sub> control are either lower in efficiency, are not proven or commercially available, or are not applicable for the WTP steam generation plant since they are not easily applied to package boilers. Package boilers have relatively small fireboxes, so there is not sufficient room available for effective use of other combustion controls, such as staged combustion or overfired air. Consequently, the other combustion control technologies are not considered to be available NO<sub>x</sub> control technologies under this BACT analysis.

The post-combustion techniques of SNCR or SCR are technically infeasible because they are commercially unavailable and are unproven for the specific application (see also section 4.5.1.4). Key constraints are imposed by the size and standard designs that are available for package boilers. For instance, the largest boilers, at 800 horse power, have a steam generation rate of less than 28,000 lb/hr at 135 psig saturated steam. These are small boilers by industrial scale. Consequently, there is no installed facility experience in applying either SCR or SNCR to boilers at this scale.

The small package boilers proposed are firetube boilers. This is a standard boiler design allowing vendors to produce cost-competitive package boilers that can be shipped to a site on skids with minimal site construction. In firetube boilers, the hot gases from the burners are passed through the tube side of a shell-and-tube heat exchanger. The water is boiled off on the shell side to produce steam. To effect high heat transfer efficiencies, high gas velocities are used on the hot gas (tube) side of the heat exchangers/boilers. This high gas velocity is combined with a short gas residence time (for example, 0.1 second in the firebox) to produce a boiler design that uses a minimal amount of materials in its construction. Consequently, the hot gas goes through a very rapid temperature change. The temperature profile is very sensitive to the boiler loading. The short residence time and the wide variability in the

temperature profile of the gas would make it very difficult to control the time-temperature ammonia concentration profile within the operating envelope required for effective control of the SNCR NO<sub>x</sub>.

A major SNCR vendor stated that development of the control scheme for a firetube package boiler would require a considerable research and development effort on the first application of the technology. Actual NO<sub>x</sub> control efficiency could only be estimated, not guaranteed, since no existing facilities use SNCR on firetube boilers. Installed SNCR experience is limited to the wall-fired or tangentially fired industrial boiler designs that are standard for any boiler of significant size (McIntyre 1994). A technology that would require experimental investigation to determine its effectiveness and applicability cannot be considered to be an available technology under the BACT guidelines. Similarly, catalyst life in the SCR process cannot be predicted because of uncertainties related to the hot-side composition of exhaust gases.

One problem with liquid fuel applications of SCR technology is that the system would have to be started up without the controls on line to avoid soaking the catalyst with wet fuel, which would deactivate the catalyst. If a problem arose with the SCR catalyst system that interfered with boiler operation, the outage of the steam plant would jeopardize operation of the far more important vitrification process plant that relies on the boilers for utility services. Finally, the fact that SCR control technology is not available commercially for small firetube boilers, makes SCR an exploratory or experimental technology for this application. Therefore, SNCR and SCR are both eliminated from further consideration as a potential BACT for the industrial boilers in the WTP air application because they are technically infeasible.

A recent (November 2001) investigation of RACT/BACT/LAER Clearinghouse data has not identified any commercial application of SCR to small package boilers fired on distillate fuel oil. A search of California BACT determinations has similarly shown that no package boilers have been constructed or operated with an SCR postcombustion control system. SCR control technology is not practiced in government or industry for distillate fuel-fired package boilers.

#### **Source Reduction-Pollution Prevention**

Another effect of the short residence time and small size of the package boilers is that they are inherently low-NO<sub>x</sub> producers. This is the preferred method for pollution control, that is, to limit the formation of pollutants at the source rather than applying post-process pollution control systems. Application of combustion controls is consistent with the pollution prevention hierarchy that specifies reduction of pollutant emissions at the source.

#### **FGR and LNB Commercial Application**

LNBs with or without flue gas recirculation are used in the package boiler industry as NO<sub>x</sub> control technology. Vendor information indicates that flue gas recirculation involving the recycling of gas into the firebox to reduce the available oxygen and temperature within the burner flame zone is an effective supplement to low-NO<sub>x</sub> burner technology which achieves reductions of NO<sub>x</sub> emissions. This technology is applied to package boilers when the flue gas is recirculated to the burner, and the technology has been fully proven in practice. Flame impingement on boiler walls/tubes causing reliability problems in some designs has been noted in the past, so only proven designs should be used.

### **4.5.3 Control Technology Hierarchy**

The available BACT control technologies for the package industrial boilers include use of LNBs, flue gas recirculation, and the possible combination of these 2 techniques. These technologies are ranked below for fuel oil combustion for steam generation in terms of EPA estimated potential for NO<sub>x</sub> removal:

- LNBs: 20 % to 50 % NO<sub>x</sub> reduction
- FGR: 58 % to 73 % NO<sub>x</sub> reduction
- FGR and LNBs: 73 % to 77 % NO<sub>x</sub> reduction
- LNB with steam atomization: greater than 70%

#### 4.5.4 Energy, Economic, and Environmental Impacts

LNBs and steam atomization technologies designed to minimize NO<sub>x</sub> formation are readily available in plans for new oil-fired package boilers. There are no significant environmental impacts associated with the use of such technology. Since these are package boilers, there are no additional capital costs for the installation of skid-mounted boilers. Operating and maintenance costs are minimal for LNBs. No additional labor increments or fuel costs are expected for either of these NO<sub>x</sub> control technologies.

However, the total capital cost for adding SCR catalyst postcombustion control to the WTP boilers is estimated to be approximately \$4,500,000. This is based on an air pollution control industry consensus estimate of the capital costs associated with a hot-side retrofit of a 200 MW pulverized coal boiler at \$65.59 per kilowatt (KW) (ICAC 1997). Capital facilities include an anhydrous ammonia storage tank, ammonia vaporizer and controls, a flue gas cooler, a catalyst bed, temperature monitors, and NO<sub>x</sub> or N<sub>2</sub> stack gas monitors. The annual cost of removal of one US ton of NO<sub>x</sub> is estimated to be \$12,554 which is considered to be excessive in light of the relatively limited benefit and the uncertainty associated with applying the technology to the WTP boilers.

A summary of BACT determinations for fuel oil-fired boilers is given in Table 4-8. LNBs are within accepted criteria for BACT for small package boilers, and are commercially available. Noncriteria pollutant emissions (including uncombusted hydrocarbons and organics) are expected to be minimized by the use of efficient air-fuel mixing, low-NO<sub>x</sub> burners.

#### 4.5.5 Selection of Proposed BACT

LNBs with steam atomization are proposed as the BACT for the distillate fuel oil-fired package boilers for the WTP steam boiler plant. The NO<sub>x</sub> reduction potential is estimated to be greater than 70 % (Niepow 2003). Limited operating hours are also proposed as BACT for 3 steam boilers operating a maximum of 3679 hours per year. Other combustion controls are not as good, not applicable, or not commercially available. Postcombustion controls are either not as effective or not technically feasible.

#### 4.6 NO<sub>x</sub> BACT for the Auxiliary and Support Systems

Three backup diesel generators will be used for the WTP. One generator will be rated at 3950 brake-horse power (bhp) (2500 KW) and 2 generators will be rated at 5530 bhp (3500 KW). The annual operation was assumed to be 164 hours based on the following assumptions:

- Each generator will be operated for 6 hours every 2 weeks for testing purposes
- An 8-hour power outage per year based on a historical power loss record (Shultz 1994)

In addition, there will be 2 fire pumps which will be powered by 300 bhp (474 KW) diesel-fired engines, less than one-tenth the size of the generator engines. Each engine is expected to be operated approximately 110 hours per year.

The maximum potential emissions from the operation of the diesel generators and the fire pump engines were estimated using the AP-42 emission factors (AP-42 Section 3.4, Table 3.4-1 for CO, NO<sub>x</sub>, SO<sub>x</sub>, particulate matter, and VOCs [total organics as CH<sub>4</sub>]) (EPA 1996). The maximum potential for the diesel generators and the fire pump engines to emit NO<sub>x</sub> is determined to be 20.8 US tons per year. NO<sub>x</sub> and other emissions from the generators will be limited by restricting the hours of testing to meet the minimum requirements. Finally, good combustion engineering practices will be followed, which include adherence to the diesel engine manufacturer's specification for operation, maintenance, and combustion control. Specified combustion feed gas ratios (including the fuel-air ratio), monitoring, and startup and shutdown procedures will be followed to maximize combustion efficiency and to minimize discharge of pollutants into the atmosphere.

#### **4.7 Summary of Proposed BACT for NO<sub>x</sub> Emissions Control for the WTP**

Table 4-9 summarizes the proposed BACT controls for NO<sub>x</sub> for the WTP.

**Table 4-1 Wet NO<sub>x</sub> Abatement Technologies**

Supplier	Process	Inlet NO <sub>x</sub> Ppm	Percent Removal	Oxidizer to NO <sub>x</sub> ratio
MHI	Oxidation absorption	100	90	1.7
IHI	Oxidative absorption	Not stated	80	N/A
Sumitomo Fujikasui	Oxidative absorption with a caustic scrubber	200 to 250	80 to 90	N/A
Chisso Eng.	Absorption oxidation	Not stated	70 to 85	5
Kureha	Absorption oxidation	200	90	N/A
Chiyoda	Oxidation absorption	Not stated	80	1.5
Not Stated	Permanganate	90	N/A	

Reference: Baide 1992



**Table 4-2 Dry NO<sub>x</sub> Abatement Technologies**

Supplier	Process	NO <sub>x</sub> inlet (ppmv)	NO <sub>x</sub> Removal (%)	NH <sub>3</sub> /NO <sub>x</sub> Molar Ratio	Gas Temperature (°F)	Ammonia Slip (ppmv)
Sumitomo Chemical	SCR	200	90	1	608	10 to 20
Hitachi Zosen	SCR	230	93	1	752	Not stated
Hitachi Ltd.	SCR	100	80 to 90	1.07	626 to 716	10
JGC	SCR	90 to 130	95 to 98	1 to 1.2	716 to 734	10
Mitsui Eng.	SCR	190	90	1	662	Not stated
Mitsubishi Heavy	SCR	120	75 to 80	.75 to .80	662 to 752	<1
IHI	SCR	Not stated	90	1	680	<10
Kurabo	SCR	280	90	1	662 to 752	<10
Kureha	SCR	Not stated	90	1 to 1.1	302	Not stated
Sumitomo Heavy	SCR	200	95	1	662	<10
Nippon	SCR	200	80 to 90	1.2 to 1.5	662 to 752	0 to 50
Ashahi Glass	SCR	500 to 700	90 to 95	1.1	662 to 752	Not stated
Acurex Corporation	SNCR process	110 to 140	40	1.5	1652 to 2102	<20
Goal Line Environmental Technologies	SCONO <sub>x</sub>	25	92	N/A	302 to 698	N/A
Ebara Corporation	Electron beam radiation process	240	80 to 90	N/A	212	N/A
Union Carbide	Molecular sieve process	100	95	N/A	Not stated	N/A
NO <sub>x</sub> SO Corporation	NO <sub>x</sub> SO	200	90	N/A	N/A	N/A

**Table 4-3 NO<sub>x</sub> Abatement Technologies**

Abatement Technology	Advantages	Disadvantages
Wet treatment - feasible	Multi-purpose, simple	Waste generators, complex
Water scrubber	Simple	Extremely large equipment required
Oxidation-absorption with caustic scrubber	Reduced equipment size requirements, more efficient	Gas-phase oxidants required, increased waste problems, more complex
Absorption-oxidation	Increased scrubbing efficiency	Extremely large equipment required, increased waste, expensive oxidants
Oxidation-complexation	High efficiency, reduced equipment size	Increased waste, costly oxidants, complex process
Wet treatment - not feasible	Not applicable	Not applicable
Other wet processes - permanganate process	Potentially high efficiency	SO <sub>2</sub> interference, difficult and unproven liquid processing, liquid waste generation
Dry reducing methods - feasible	Simple, no waste, well developed	Requires reductant, aerosol sensitive, high temperature
SCR	Well established, efficient, safe	Requires NH <sub>3</sub> control, requires temperature control, NH <sub>3</sub> and N <sub>2</sub> O possible effluents
SNCR	Extremely simple	Low efficiency, not well developed, very high temperature, tight temperature control required
SCONO <sub>x</sub> catalytic absorption	No NH <sub>3</sub> addition or NH <sub>3</sub> slip	Not tested or proven in the nuclear industry, natural gas supply needed
Other dry methods - not feasible	Not applicable	Not available or not feasible
NCR	Efficient	High fuel use, costly, O <sub>2</sub> -depleted streams only
Electron beam radiation	Simple, no service requirements, no aqueous wastes, remote, compatible with existing equipment	Extremely large radioactive source required, may require chemical additives, developmental stage only
Molecular sieve adsorption	Efficient	Large equipment requirements, high energy, complex, waste generator, needs nitric acid plant
NO <sub>x</sub> SO	NO <sub>x</sub> removal increases with increasing SO <sub>x</sub> concentration	Effective only for NO <sub>x</sub> generated in coal combustion

**Table 4-4 Ranking of Technically Feasible Control Technologies by Expected Control Efficiency**

NO <sub>x</sub> Abatement Technology	Maximum NO <sub>x</sub> Control Efficiency (%)	Expected NO <sub>x</sub> Control Efficiency (%)	LAW Offgas Annual NO <sub>x</sub> Removal <sup>a</sup> (US tons per year)	HLW Offgas Annual NO <sub>x</sub> Removal <sup>b</sup> (US tons per year)	Environmental Impact
SCR	99	95	837	162	Catalyst replacement, ammonia slip
Oxidation-complexation	90	90	793	153	Wastewater
Permanganate solution absorption	90	90	793	153	Wastewater
Absorption-oxidation	90	87	766	148	Wastewater
Oxidation-absorption with caustic scrubber	90	85	749	145	Wastewater, ozone
Water scrubber	60	50	440	85	Wastewater
SNCR	80	45	396	77	Ammonia slip

a Based on an uncontrolled NO<sub>x</sub> emission rate of 881 US tons per year (24590-WTP-RPT-MRQ-PO-03-002).

b Based on an uncontrolled NO<sub>x</sub> emission rate of 170 US tons per year (24590-WTP-RPT-MRQ-PO-03-002).

**Table 4-5 Summary of Cost Analysis for LAW Vitrification Plant**

<b>Control Technology</b>	<b>Capital Cost</b>	<b>Annual Operating Cost</b>	<b>Annualized Cost (40-year life)</b>	<b>US Tons of NO<sub>x</sub> Removed Annually (removal efficiency)</b>	<b>Cost Effectiveness (\$/US ton of NO<sub>x</sub> removed)</b>
SCR	\$2,122,360	\$118,219	\$335,324	837 (95 %)	\$400.60
SNCR	\$750,672	\$47,717	\$124,480	396 (45 %)	\$313.99
SBS	\$6,824,792	\$237,188	\$935,087	793 (90 %)	\$1179.33
Caustic scrubber	\$529,256	\$48,322	\$102,443	749 (85 %)	\$136.80

**Table 4-6 Summary of Cost Analysis for HLW Vitrification Plant**

<b>Control Technology</b>	<b>Capital Cost</b>	<b>Annual Operating Cost</b>	<b>Annualized Cost (40-year life)</b>	<b>US Tons of NO<sub>x</sub> Removed Annually (removal efficiency)</b>	<b>Cost Effectiveness (\$/US ton of NO<sub>x</sub> removed)</b>
SCR	\$562,675	\$71,503	\$129,041	162 (95 %)	\$796.55
SNCR	\$247,355	\$32,617	\$57,911	77 (45 %)	\$752.09
SBS	\$1,664,203	\$55,370	\$225,551	153 (90 %)	\$1474.18
Caustic scrubber	\$140,021	\$9,645	\$23,963	145 (85 %)	\$165.26

Table 4-7 NO<sub>x</sub> Control Options for Oil-Fired Boilers<sup>a</sup> (Boilrank)

Control Technique	Description of Technique	NO <sub>x</sub> Reduction Potential (%) <sup>b</sup>		Range of Application	Commercial Availability/ Research and Development Status	Comments
		Residual Oil	Distillate Oil			
Combustion Control						
Burners Out of Service (BOOS)	One or more burners on air only; remainder of burners firing fuel-rich	10 to 30	ND <sup>c</sup>	Most effective on boilers with 4 or more burners in a square pattern	Available	Requires careful selection of BOOS pattern and control of airflow. May result in boiler de-rating unless fuel delivery system is modified.
Reduced Air Preheat (RAP)	Bypass of combustion air preheater	5 to 16	ND	Combustion air temperature can be reduced to ambient conditions	Available	Application of this technique on new boilers requires installation of alternate heat recovery system, (for example, an economizer).
Oil/Water Emulsified Fuel	Oil/water fuel with emulsifying agent	41	ND	Firetube boilers	Available but not widely demonstrated	Thermal efficiency reduced due to water content.
Load Reduction (LR)	Reduction of air and fuel flow to all burners in service	33 to increase of 25 %	31 to increase of 17 %	Applicable to all boiler types and sizes. Load can be reduced to 25 % of maximum	Applicable in retrofit applications	Technique not effective when it necessitates an increase in excess O <sub>2</sub> levels. LR possibly implemented in new designs as reduced combustion intensity (for example, an enlarged furnace plan area)
Low Excess Air (LEA)	Reduction of combustion air	0 to 28	0 to 24	Generally, excess O <sub>2</sub> can be reduced to 2.5 % representing a 3 % drop from baseline	Available for boilers with sufficient operational flexibility	Added benefits included increase in boiler efficiency. Limited by increase in CO, HC, and smoke emissions

Table 4-7 NO<sub>x</sub> Control Options for Oil-Fired Boilers<sup>a</sup> (Boilrank)

Control Technique	Description of Technique	NO <sub>x</sub> Reduction Potential (%) <sup>b</sup>		Range of Application	Commercial Availability/ Research and Development Status	Comments
		Residual Oil	Distillate Oil			
Staged Combustion (SC)	Fuel-rich firing burners with secondary combustion air ports	20 to 50	17 to 44	70 to 90 % burner fuel-air stoichiometry can be used with proper installation of secondary air ports	Technique is applicable on packaged and field-erected units. However, it is not yet commercially available for all designs.	Best implemented on new units; retrofit is probably not feasible for most units, especially packaged ones.
Low-NO <sub>x</sub> Burner (LNB)	New burner designs with controlled air/fuel mixing and increased heat dissipation	20 to 50	20 to 50	New burners generally applicable to all boilers	Commercially available	Specific emissions data from industrial boilers equipped with LNB are lacking.
Flue Gas Recirculation (FGR)	Recirculation of portion of flue gas to burners	15 to 30	58 to 73	Up to 25 to 30 % of flue gas recycled; can be implemented on most design types	Available; best suited for new units.	Requires extensive modifications to the burner and windbox; possible flame instability at high FGR rates.
FGR and Staged Combustion/LNB	Combined techniques of FGR and staged combustion or LNB	25 to 53	73 to 77	Maximum FGR rates set at 25 % for distillate oil and 20 % for residual oil	Available for boilers with sufficient operational flexibility.	May not be feasible on all existing boiler types; best implemented on new units.

Table 4-7 NO<sub>x</sub> Control Options for Oil-Fired Boilers<sup>a</sup> (Boilrank)

Control Technique	Description of Technique	NO <sub>x</sub> Reduction Potential (%) <sup>b</sup>		Range of Application	Commercial Availability/ Research and Development Status	Comments
		Residual Oil	Distillate Oil			
Catalytic Combustion <sup>d</sup>	Combustion of fuel inside monolithic honeycomb channels coated with precious metal catalyst at temperatures below those triggering thermal NO <sub>x</sub> formation	>90	>90	NO <sub>x</sub> formation from prompt NO <sub>x</sub> and fuel-bound nitrogen only	Not commercially available. Tested in pilot plant at 1mm Btu/hr scale	Technology development has not progressed. Thermal and structural problems with ceramic substrate and catalyst durability. High risk R+D effort would be needed and economic competitiveness would still be questionable
<b>Postcombustion Controls</b>						
SNCR	Injection of NH <sub>3</sub> or urea as a reducing agent in the flue gas	40 to 70	40 to 70	Applicable for large packaged and field-erected watertube boilers. May not be feasible for firetube boilers	Commercially offered but not widely demonstrated on large boilers	Elaborate reagent injection, monitoring, and control systems required. Possible load restrictions on boilers and air preheater fouling when burning high sulfur oil. Must have sufficient residence time at correct temperature
SCR	Injection of NH <sub>3</sub> in the presence of a catalyst (usually upstream of air heater)	90	90	Typically large boiler designs	Commercially offered but not widely demonstrated. Not demonstrated on small firetube boilers	Applicable to most boiler designs as a retrofit technology or for new boilers

a Reference: Section 1.3, Fuel Oil Combustion, AP-42, 4th edition, through Supplement E, September 1998, OAQPS, EPA (EPA 1998b).

b Reduction estimate ranges based on wide range of sizes of retrofit or replacement of older boilers with baseline NO<sub>x</sub> emissions that are estimated to be roughly in the range of 0.3 to 0.5 lb NO<sub>x</sub>/mmBtu. Actual reduction levels may not be achieved in practice because of fuel-bound nitrogen and design/scale limitations but levels can be used for ranking of options.

c ND = no data.

d Reference: Vendor information, Engelhard Corporation (Farrauto 1999).

**Table 4-8 EPA RBLC Query Results - NO<sub>x</sub> Control - No. 2 Fuel Oil Fired Boilers**

Permit Date	Facility	RBLC ID	Process	Capacity	NO <sub>x</sub> Emission Factor	Other Emission Limits/Comments	Basis of Regulatory Limit
24 October 2001	AES Red Oak LLC, NJ	NJ-0036	Auxiliary boiler	99.0 mmBtu/hr	0.10 lb/mmBtu	Boiler use limit set to 3600 hours per year	LAER
1 January 1998	Proctor and Gamble Paper Products, MO	MO-0051	Boiler, No. 2 fuel oil	265.7 kgal/yr	0.17 lb/mmBtu	Low-NO <sub>x</sub> fuel, Good Combustion	BACT-PSD
9 July 1998	Archer Daniels Midland Co. - Northern Sun Vegetable Oil, ND	ND-0018	Boiler, Backup oil	28.0 mmBtu/hr	5.8 lbs/hr	Limited hours	BACT-PSD
14 January 1997	MERK Rahway Plant, NJ	NJ-0045	Boiler, No. 2 fuel oil	99.5 mmBtu/hr	10.0 lbs/hr	Low-NO <sub>x</sub> burner	BACT-PSD
29 May 1997	Toyota Manufacturing, USA, Inc., KY	KY-0068	Boiler, Fuel oil	96.0 mmBtu/hr	0.20 lb/mmBtu	Operating hours, 2628 hr/yr	BACT-PSD
3 April 1996	Mid-Georgia Cogeneration, GA	GA-0063	Boiler, fuel oil	60.0 mmBtu/hr	0.15 lb/mmBtu	Dry Low NO <sub>x</sub> burner with FGR	BACT-PSD
9 June 1995	International Flavors and Fragrances, NJ	NJ-0028	Boiler, No. 2 fuel oil	96.0 mmBtu/hr	.225 lb/mmBtu	Operating hours, 1440 hr/yr	RACT
14 April 1993	Black Hills Power & Light Co., WY	WY-0046	Auxiliary boiler	30.76 mmBtu/hr	0.20 lb/mmBtu	6.2 lb NO <sub>x</sub> /hr	Other
20 May 1993	WGP, Inc., ME	ME-0029	Boiler, No. 2 fuel oil	91.6 mmBtu/hr	0.22 lb/mmBtu	Low-NO <sub>x</sub> burners, Flue Gas Recirculation	BACT-PSD
30 July 1993	Gordonsville Energy L.p., VA	VA-0202	Auxiliary boiler, No. 2 fuel oil	22.0 mmBtu/hr	3.7 lbs/hr	Low-NO <sub>x</sub> burner	NSPS

Note:

RBLC is the EPA RACT/BACT/LAER Clearinghouse for pollution controls required to meet CAA regulations (EPA 2003a).

RBLC search based on: (1) Process Category: Commercial/Institutional -Size Boilers/Furnaces (100 million Btu/hr or less), (2) Process Type: 13.220 - Distillate Fuel Oil (ASTM # 1,2, includes kerosene, aviation, diesel fuel), and (3) Entries added since June 1993.



**Table 4-9 Summary of Proposed BACT for NO<sub>x</sub>**

Source	Control Technology	Approximate Control Efficiency
Pretreatment	Operating practices to minimize NO <sub>x</sub> emissions, caustic scrubber	Not applicable
LAW melter offgas	SCR	greater than/equal to 95 %
HLW melter offgas	SCR	greater than/equal to 95 %
Steam boilers	Low NO <sub>x</sub> burners, steam atomization, limited operating hours	greater than 70%
Backup generators and fire pump engines	Good combustion engineering practices, limited operating hours,	Not applicable

## Contents

<b>5</b>	<b>BACT Analysis for Particulate Matter.....</b>	<b>5-1</b>
5.1	BACT Analysis Methodology.....	5-1
5.2	Particulate Matter BACT for the WTP Processing and Ventilation Systems.....	5-1
5.2.1	Identification of Control Technology Options.....	5-2
5.2.2	Elimination of Technically Infeasible Options.....	5-4
5.2.3	Ranking of Technically Feasible Control Options.....	5-5
5.2.4	Evaluation of the Most Effective Controls.....	5-7
5.2.5	Environmental, Energy and Economic Impacts for Radionuclide Particulates and Aerosols.....	5-7
5.2.6	Selection of Proposed BACT.....	5-8
5.3	PM BACT for the Steam Boiler Plant.....	5-8
5.3.1	Identification of Particulate Matter Control Technology Options for the Steam Boiler Plant.....	5-8
5.3.2	Technical Feasibility Considerations.....	5-20
5.3.3	Control Technology Hierarchy.....	5-20
5.3.4	Energy, Economic, and Environmental Impacts.....	5-21
5.3.5	Selection of Proposed BACT.....	5-21
5.4	PM BACT for the Auxiliary and Support Systems.....	5-22
5.4.1	PM BACT for Standby Diesel-Fired Generators.....	5-22
5.4.2	PM BACT for Glass Former Facility.....	5-28
5.5	Summary of Proposed BACT for PM Emissions Control for the WTP.....	5-28

## Tables

Table 5-1	BACT Control Technology Screening for WTP Process Streams.....	5-29
Table 5-2	BACT Technology Ranking by Effectiveness for Control of Particulates for WTP Process Streams.....	5-32
Table 5-3	Compilation of Facility Emission Limits for Boilers Firing #2 Diesel.....	5-33
Table 5-4	Hierarchy of Potential Control Efficiencies <sup>a</sup> for Technically Feasible Particulate Matter Control Equipment.....	5-35
Table 5-5	Summary of Potential Energy Impacts for Particulate Control Technology Options.....	5-35
Table 5-6	Summary of Potential Economic Impacts for Particulate Control Technology Options (EPA 2003b).....	5-36
Table 5-7	Summary of the Environmental Impacts of Particulate Matter Control Options.....	5-36
Table 5-8	Diesel-Fired Engines Control Technology.....	5-37
Table 5-9	PM Abatement Technologies.....	5-37
Table 5-10	Ranking of Technically Feasible Control Technologies by Expected Control Efficiency.....	5-38

Table 5-11 PM Control Options for Standby Diesel Engines .....5-39

Table 5-12 Ranking of Particulate Control Options for Diesel Generators.....5-39

Table 5-13 Results of BACT Evaluation for Control of Radionuclide and All Particulates .....5-40

## 5 BACT Analysis for Particulate Matter

A BACT analysis for PM<sub>10</sub> emissions was conducted for the following point source emission units within the proposed WTP facility. This BACT analysis has been prepared for the following sources:

- Pretreatment processing
- LAW vitrification processing
- HLW vitrification processing
- Steam boiler plant
- Generators
- Glass former facility

### 5.1 BACT Analysis Methodology

This section has been prepared in accordance with the EPA top-down, 5-step guidance process. A complete BACT analysis methodology discussion is provided in section 4.1.

### 5.2 Particulate Matter BACT for the WTP Processing and Ventilation Systems

The WTP consists of 3 separate process facilities housed in different buildings—pretreatment, LAW vitrification, and HLW vitrification, which are involved in the production of vitrified glass logs containing the tank waste, and an onsite analytical laboratory. These WTP facilities are equipped with ventilation systems, primarily designed to isolate sources of particulate contamination to protect human health and the environment. These facilities are custom designed and engineered, and there are some very high radioactive environments in these buildings. Consequently, the proper operation and maintenance of control equipment and systems pose some unique and difficult challenges. There is also a potential human health concern if control equipment failure occurs in this specialized application.

Therefore, 2 criteria are of paramount importance in determining the BACT for the WTP processing facilities and the analytical laboratory:

- Use of demonstrated control technologies that have been applied to other nuclear facilities.
- Use of control technologies that allow maximum control efficiencies, in order to reduce the emissions of radionuclide particles consistent with the best available radionuclide control technology (BARCT).

The State of Washington Department of Health (WDOH) has been designated as the state agency responsible for regulating radioactive air emissions. The particulate emissions from the WTP will consist of radioactive particulate and non-radioactive particulate emissions. The WTP has submitted 24590-WTP-RPT-ENV-01-008, *Radionuclide Air Emissions Notice of Construction Permit Application for the River Protection Project - Waste Treatment Plant*, and 24590-WTP-RPT-ENV-01-004, *Best Available Radionuclide Control Technology Analysis for the WTP*, describing the radionuclide air emissions and proposed radionuclide control technologies for the process and ventilation emission units.

This BACT analysis proposes the best available control technology for the nonradioactive particulate air emissions from the 3 process facilities and is consistent with the proposed best available radionuclide control technology for air emissions.

The 3 WTP process facilities and the process emission units are briefly described below. Each facility also has 3 separate ventilation system emission units ventilating the C2, C3, and C5 areas. The C2 area typically consists of non-process operating areas, access corridors, and control, instrumentation, and electrical rooms. The C3 area will consist of filter plant rooms, workshops, maintenance areas, and monitoring areas. The C5 area consists of a series of process cells where waste will be stored and treated.

These emission units comprise the WTP processing facility, for the purposes of this analysis.

#### **Pretreatment Process**

The pretreatment processes have the lowest emission rates of radionuclide and air toxic particulates, in comparison with the vitrification processes. The emissions units from the pretreatment facility are the pretreatment building ventilation system; the process vessel vents (PT-S3); and the reverse flow diverters/pulse jet mixers (RFDs/PJMs) (PT-S4).

#### **LAW Vitrification Process**

The vitrification processes contribute the highest unabated air toxic and radionuclide particulate emission rates, with the LAW vitrification process having a significantly smaller contribution than the HLW vitrification process. Emissions units from LAW vitrification include the LAW building ventilation system and the LAW melter offgas and process vessel vents (LV-S3).

#### **HLW Vitrification Process**

The HLW vitrification process contributes the highest unabated air toxic and radionuclide particulate emission rates. Emissions sources from HLW vitrification include the HLW building ventilation system; and 1 flue from each of the 2 HLW melters (HV-S3-1 and HV-S3-2) which collect the emissions from the HLW melter offgas and process vessel vents. In addition, there is HV-S4, which collects emissions from the RFDs/PJMs.

#### **Analytical Laboratory**

The WTP analytical laboratory emissions will consist of emissions from building air ventilation systems, hot cell ventilation, and sample analysis fume hood exhaust.

### **5.2.1 Identification of Control Technology Options**

This section identifies available technology options that may be used to control PM<sub>10</sub> emissions from the WTP processing facility. Information regarding available control technologies is provided in this section, and was obtained from:

- The EPA's RACT/BACT/LAER clearinghouses
- Previous BARCT demonstrations
- Regulatory authorities

- Control technology vendors
- Literature search
- Internet search
- Similar commercial and government applications

Available control options are those air pollution control technologies that have a practical potential for application to the process emissions and are available from a vendor. Control technologies include not only equipment to remove or treat releases, but also measures to prevent or reduce emissions. A list of 27 control technologies was developed in the BARCT analysis for the WTP (24590-WTP-RPT-ENV-01-004). That report contains a list of references from a RACT/BACT/LAER clearinghouse review and a literature search that was performed for technologies pertaining to the control of radionuclide emissions. Information was also gathered from Internet searches of DOE, Nuclear Regulatory Commission, EPA web sites, and University of California library databases. Resources used from these databases include publications from DOE laboratories and EPA programs, and proceedings of DOE nuclear air cleaning conferences. Existing references from previous Hanford BARCT analyses were also utilized. Additional information was obtained from publicly available documents from existing nuclear facilities in the United States and other countries.

The control technologies identified are as follows:

- Baghouse (fabric filter)
- Prefilter (roughing filter)
- High-efficiency metal filter (HEMF)
- High-efficiency porous ceramic filter
- HEPA filters
- Ultra-low penetration air (ULPA) / very large-scale integration (VLSI) filter
- Deep bed sand filter
- Deep bed glass fiber filter
- HEMEs
- Standard mist eliminators
- Dry electrostatic precipitator (ESP)
- Wet electrostatic precipitator (WESP)
- Ejector venturi scrubber (EVS) hydrosonic air atomized scrubber (AAS)
- Hydrosonic scrubbers (HSS)
- Hydrosonic steam atomized scrubber (SAS)
- Impingement scrubber
- Impingement-plate / tray tower scrubber
- Mechanically-aided scrubber
- Packed-bed / packed-tower wet scrubber
- Spray tower
- Spray-chamber / spray-tower wet scrubber

- SBSs
- Tray tower
- Cyclonic wet scrubbers
- Multiple cyclones (multiclones)
- Reverse-flow cyclone collector

Those technologies are described in detail in the BARCT document for the WTP (24590-WTP-RPT-ENV-01-004).

### **5.2.2 Elimination of Technically Infeasible Options**

Table 5-1 lists the 27 control technology options so they can be checked for use in the WTP process streams for particulate matter control. As noted in the table, 12 of them were eliminated as not applicable for the process for the reasons given in the comment section. The general screening criteria developed in the BARCT document for the WTP (24590-WTP-RPT-ENV-01-004) were used to eliminate infeasible options, as follows:

- The control technology has not been demonstrated at a sufficient scale for application to the WTP.
- The control technology introduces additional hazards above and beyond the primary control hazard.
- The control technology uses materials of construction that are unsuitable in a radiation field anticipated during operations and where no suitable alternative materials can be substituted.
- The control technology would be very difficult to modify for applicable remote operations and maintenance activities anticipated during operations.
- The control technology requires testability requirements where extraordinary measures would be required to ensure operational performance.
- The footprint or overall height required by the technology is of a scale not suitable for containment within a hot cell.

### **WTP Radioactive Operating Environment**

Unique to the nuclear industry is the hostile operating environment of intense radiation. Equipment is located behind heavy shielding walls to keep the radiation exposure to operating personnel as low as reasonably achievable (ALARA). Equipment used in a radiochemical process requires special features for the installation into the heavily shielded cell. These features make it impossible for operating personnel to directly assist in the installation of a replacement. An operator using closed circuit television will most likely perform the removal of a failed piece of equipment remotely from a shielded location.

The feasibility of transferring a technology from a non-nuclear application to a nuclear application like the WTP without encountering irresolvable technical difficulties depends on the ability to fit the equipment with special features that will enable installation or replacement/removal in a shielded cell remotely, using a bridge crane, for example.

The transfer of a technology from a non-nuclear application to a nuclear application like the WTP requires the equipment to be fabricated with special connectors and trunion guide internals. High maintenance components are preferably serviced or replaced using a bridge crane or other equipment that

is operated by remote control, avoiding the need to remove the entire piece of equipment to the decontamination cell for cleaning. The repair or replacement of the failed component can then take place after the cleaning of the equipment piece has reduced the radiation field to an acceptable level. High radiation levels may result in replacement of a major equipment piece rather than repair because the dose to maintenance personnel, while acceptable, is near the limits of occupational exposure. This limited maintenance capability in the WTP operating environment may present unresolved technical difficulties for some of the identified technologies. A critical step in the feasibility analysis is the determination of maintainability in a radioactive environment. If a technology requires frequent hands-on maintenance, necessitating lengthy shutdown and causing a high exposure to the operators, then the technology is deemed infeasible.

### **High Efficiency Fiber Filters (Metal and Ceramic)**

High efficiency fiber filters are composed of ceramic or stainless steel fibers sintered together into a mat, giving the filter high loading capacity, high strength, and low pressure drop. Removal efficiencies of up to 99.97 % can be achieved for particles greater than 0.1  $\mu\text{m}$ . High efficiency fiber filters can tolerate high temperatures and wet conditions, though their removal efficiency can be quite low when wet. Additionally, free liquids with dissolved acid gases negatively affect the metal-type filters. The ceramic-type filters are best for high-temperature, corrosive, or abrasive environments. The steel filters can be welded into steel housings or frames, eliminating the need for gaskets and adhesives. Although only recently used in low flow rate streams in the nuclear industry, high HEMFs have been commercially available for about 14 years (Fluor Daniel 1991). These filters can be cleaned in place or removed and cleaned. The duration between cleanings depends on the particle loading and the number of filters used.

HEMFs are a relatively new gas filter concept being considered for nuclear air and gas cleaning applications. Little documented experience is available on extended performance in large-scale applications with HEMFs as the final stage of particulate control technology. HEMFs were assessed for use in the HLW vitrification facility as described in RPT-W375HV-PR00001, *HLW Vitrification Process Offgas System Evaluation*. Available information on the application of HEMF equipment in large-scale radioactively contaminated environments is insufficient to determine the long-term suitability of HEMF equipment. HEMF filters are not AG-1 qualified. The term "AG-1 qualified" refers to a document containing codes and standards for all engineered safety features for nuclear air and gas treatment equipment and systems, authored and maintained by the Committee on Nuclear Air and Gas Treatment (CONAGT) under the American Society of Mechanical Engineers (ASME 1997).

In addition, there are technical concerns with HEMF use for which long-term operating experience is not available. Chemical cleaning agents such as nitric acid could affect the filter media structure (that is, by corrosion) as the number of cleaning cycles increases, which may affect removal efficiency. The ability to clean the HEMF after 1 or more cycles has not been demonstrated. This may result in decreasing capacity with time and eventual plugging if not successful. For these reasons, application of the HEMF control technology for the WTP process streams has been found to be infeasible.

### **5.2.3 Ranking of Technically Feasible Control Options**

Table 5-2 lists the remaining 15 technology control options ranked by average particulate matter removal efficiency. As illustrated there, it was determined that HEPA filters demonstrate the highest particulate removal efficiencies of all the options found to be technically feasible for the WTP. A brief description of the HEPA technology and its applicability to the WTP processes follows.



### High-Efficiency Particulate Air (HEPA) Filters

HEPA filters consist of fine fibers or a series of pleated or folded strips. Materials vary, but generally these are made of synthetic fibrous materials. The principle of this type of filtration is not to restrict the passage of particulates by the gap between fibers, but to alter the airflow streamlines. The airflow will slip around the fiber, but any higher-density aerosols or particulate matter will not change direction as rapidly, and as a result of their inertia (velocity), will tend to impact the fiber. Once attached, most particulates will not be re-entrained in the air stream.

HEPA filters are classified by their minimum collection efficiency. Many international standards and classes currently exist for high efficiency filters. In general, HEPA filters are defined as having an efficiency rating of 99.95 % (based on in-place testing) for the removal of 0.3  $\mu\text{m}$  diameter or larger particulates.

Some extended media filters are capable of much higher efficiencies. Commercially available filters can control particulates with 0.01  $\mu\text{m}$  diameter at efficiencies of 99.99+ % and particulates with 0.1  $\mu\text{m}$  diameter at efficiencies of 99.9999+ %. Several factors determine HEPA filter collection efficiency. These include gas filtration velocity, particle characteristics, and filter media characteristics. In general, the collection efficiency increases with increasing velocity and particle size. In addition, the collection efficiency increases as the dust cake thickness and density increases on the filter.

Individual HEPA filters are currently limited to low capacity airflow applications. Standard filter packs are factory-built, off-the-shelf units. They may handle from less than 4 up to 35 standard cubic feet per second ( $\text{ft}^3/\text{sec}$ ). HEPA filter systems designed for nuclear applications require higher capacities. For these applications, filter banks, or modules are ducted together in parallel to increase airflow capacity. Commercially available modular systems can accommodate airflow rates in the range of 180  $\text{ft}^3/\text{sec}$  to 420  $\text{ft}^3/\text{sec}$ .

Airflow capacity is a function of the resistance or pressure drop across the filter and particle loading. As the dust cake forms on the filter, the resistance increases, and therefore the airflow rate decreases. Since the filter is not clean, the airflow rate continues to decrease as the system operates. After the pressure drop across the filter reaches a point that prevents adequate airflow, the filter must be replaced and disposed of. For these reasons, HEPA filters are used in applications that have low airflow rates or have low concentrations of particulates.

Temperatures are limited by the type of filter media and sealant used in the filter packs. Standard cartridges can accommodate gas temperatures up to about 200 °F. With the appropriate construction materials, commercial HEPA filters can accept temperatures of up to 400 °F. HEPA filters with ceramic or glass packing mechanical seals can accept temperatures up to 1000 °F.

Spray coolers or dilution air can be used to lower the temperature of the pollutant stream. This prevents the temperature limits of the filter from being exceeded. However, lowering the temperature increases the humidity of the pollutant stream. HEPA filters can tolerate some humidity. However, humidity higher than 95 % can cause the filter media to plug, resulting in failure. Therefore, the minimum temperature of the pollutant stream must remain above the dew point of any condensable in the stream. The filter and associated ductwork should be insulated and possibly heated if condensation could occur.

Typical pollutant loading ranges from 6E-05 to 2E-03 pounds per cubic foot ( $\text{lb}/\text{ft}^3$ ). Dust holding capacity compares the weight gain of the filter to the rise in pressure drop during a specific period of time

(airflow volume). Typical inlet dust holding capacities range from 1-2 lb per 1000 scfm. HEPA filters are best used in applications that have low concentrations of particulates or prohibit cleaning of the filter. Moisture and corrosive content are the major gas stream characteristics requiring design consideration. As discussed previously, humidity up to 95 % is acceptable with the proper filter media, coatings, and filter construction. Filters are available that can accommodate corrosive gas streams with concentrations up to several percent. These filters are constructed of special materials and are generally more expensive (EPA 2000).

Safe-change HEPA filter housings are designed and installed to facilitate changing filters while maintaining emissions and worker exposure to ALARA. Safe-change is a term used by WTP to describe a process to change HEPA filters, also known as a bag-in, bag-out filter change method. The process involves removing a spent filter, concertina fashion, into a plastic bag that has been secured to a filter housing access opening. The spent filter is moved to the bottom of the bag, then the bag is cut to remove the spent filter for disposal. A new filter is installed using a similar process where a new filter is placed inside a new bag. This bag is placed over the same housing opening and the remnant of the first bag. Upon completing installation of the new filter, a bag remains in place (behind the filter housing door) to support the next filter change task.

#### **5.2.4 Evaluation of the Most Effective Controls**

As shown in the ranking table (Table 5-2), HEPA filters are ranked at the top in terms of particulate matter removal efficiency. HEPA filters have been used for many years in nuclear applications for particulate and aerosol removal, and are AG-1 qualified. Experience also shows that HEPA filters requiring maintenance can be replaced to return the filter installation to the original 99.95 % removal efficiency. This practical application experience demonstrates that HEPA filters consistently attain a removal efficiency of 99.95 %. For these reasons, the WTP project is proposing HEPA filters as BACT for particulate and aerosol control.

High-efficiency mist eliminators (HEMEs) were considered in WTP offgas system designs to reduce radioactive particulate emissions and to prevent HEPA filters from rapid loading, which requires frequent change-outs. The need to include a HEME in LAW was evaluated, and it was determined that the additional particulate removal provided by a HEME was not necessary in LAW. This conclusion is based on the following:

- The lower source term in LAW, as compared to HLW
- Prototypical offgas system test data received from the Vitreous State Laboratory
- HEMEs will be used in HLW to reduce radioactive particulate emissions and reduce required change-outs for HEPA filters.

#### **5.2.5 Environmental, Energy and Economic Impacts for Radionuclide Particulates and Aerosols**

The environmental, energy, and economic impacts are evaluated beginning with the most effective control option. Since the most effective feasible technology is proposed as BACT, details of the environmental, energy, and economic impacts would be important only if the most effective control option were selected. HEPA filters are a cost-effective, technically feasible control technology, and they are proposed as BACT for process, building, and laboratory air ventilation systems throughout the

Hanford Site. Therefore, HEPAs are proposed as BACT for control of particulate and aerosol emissions from all the WTP process and building air ventilation systems.

### **5.2.6 Selection of Proposed BACT**

The technology with the highest removal efficiency for particulates and aerosols is proposed as BACT for the pretreatment facility, the LAW vitrification facility, the HLW vitrification facility, and the analytical laboratory ventilation systems. Selection of HEPA filters is consistent with their designation as BACT for building air ventilation systems across the Hanford Site.

The BACT analyses were based on single-stage HEPA filtration with a removal efficiency of 99.95 %. A single stage of HEPA filtration is proposed as BACT for the C2 and C3 emission units in the pretreatment, HLW, and LAW facilities, and the laboratory emission units. Two stages of HEPA filtration are proposed as BACT for the C5 area emission units. The decision to use a single stage or 2 stages of HEPA filters is related to control of radionuclide emissions as described in the BARCT document for the WTP (24590-WTP-RPT-ENV-01-004).

### **5.3 PM BACT for the Steam Boiler Plant**

For the purposes of this analysis, all particulate matter generated by the proposed WTP has been assumed to be PM<sub>10</sub>. As identified by the EPA (EPA 1998c), 50 % of the particulate is less than 10 micrometers in diameter, but specific data does not allow determination of the actual particle size distribution that will be achieved for the WTP boilers.

Industrial boilers are operated in the boiler plant to provide high pressure steam for the WTP. These boilers are classified as particulate matter emission units for the proposed new WTP source. The boilers are complete packaged units designed for automatic operation. They will emit particulate matter at a rate significantly below EPA's New Source Performance Standards for Fossil-Fuel-Fired Generators specified in 40 CFR 60.42, which is 0.1 pound of particulate matter per mmBtu heat input. The boilers will also meet the requirement that they not exhibit greater than 20 % opacity, except for one 6-minute period per hour of not more than 27 % opacity.

Table 5-3 provides a summary of PM<sub>10</sub> (particulate matter less than 10 microns in diameter) emissions from a range of boilers firing no. 2 distillate fuel oil that are rated less than 100 mmBtu/hour (as are the boilers planned for use at the WTP for high pressure steam generation. The data was obtained from a query of the EPA RACT/BACT/LAER Clearinghouse database (EPA 2003a). This table shows a variety of applications for fuel oil combustion in different states around the country. Some limits are specified by firing rate (such as pounds of particulate matter per mmBtu), some limits are by total allowable fuel consumption, some have operational limits, and all have annual emission limits under different state implementation of BACT-PSD regulations.

#### **5.3.1 Identification of Particulate Matter Control Technology Options for the Steam Boiler Plant**

This paragraph describes the various techniques that have been frequently used to control PM<sub>10</sub> emissions from small boilers firing no. 2 fuel oil and other related combustion units. In accordance with EPA BACT guidance, the control options considered should have a practical potential for application to the emission unit identified.

A list of potential candidates for consideration as BACT for particulate matter control has been developed. EPA's RACT/BACT/LAER Clearinghouse, state air quality permits and permit applications, pollution control equipment vendor information, and relevant technical literature was reviewed. In addition, information was received from discussions with regulatory agency and control equipment vendor personnel. The following particulate matter control technologies are available for consideration as BACT for the WTP steam boiler plant:

- Pretreatment systems
- Electrostatic precipitators
- Fabric filters
- Wet scrubbers
- Incinerators
- Combined systems
- Fuel substitution and source reduction

#### **Pretreatment Systems**

Pretreatment of gas streams can be accomplished by using: 1) precollection devices, which include settling chambers, elutriators, momentum separators, mechanically aided separators, and cyclones; and 2) flue gas conditioning to modify the characteristics of the gas stream and particles to enhance particle removal in the primary control device.

#### **Electrostatic Precipitators**

Electrostatic precipitators collect particles by ionization of the gas stream and collecting ionized particles on oppositely charged surfaces. They include dry and wet process systems.

#### **Fabric Filters**

Fabric filters include baghouse systems to capture particulate matter by a number of physical mechanisms, followed by collection and removal of particles, utilizing a broad variety of designs tailored to the characteristics of the gas stream to be treated. Other fabric filtration devices are also available, including HEPA filter systems and other configurations.

#### **Wet Scrubbers**

Wet scrubbers rely on direct and irreversible contact of a liquid (usually water) with particulate matter. Then the particulate matter can be separated from the gas stream with the condensed liquid.

#### **Incinerators**

Incinerators are used to oxidize particulate matter in the form of carbon or soot to carbon dioxide by combustion in air.

### **Combined Systems**

Combined systems of the basic types of control equipment can be assembled to achieve improved performance relative to operation of individual control devices.

### **Fuel Substitution and Source Reduction**

Finally, fuel substitution and source reduction strategies may be successfully used to reduce the emissions of particulate matter from various process operations.

#### **5.3.1.1 Pretreatment Systems**

##### **Pre-Collection Devices**

Cyclones use centrifugal force to separate particulate from gas streams. They belong to the broader family of mechanical collectors, which use a variety of mechanical forces to collect particulate. A multiple cyclone is an array of a large number of small (several-inch diameter) cyclones in parallel. Multiple cyclones have overall mass removal efficiencies of 70 % to 90 %. However, cyclone collection efficiencies fall off rapidly with particle size, so that control of  $PM_{2.5}$  is limited. While no accurate statement of collection efficiency can be made without precise details of the cyclone design and fly ash properties, cyclone removal efficiencies will be 90 % or greater for 10 micron particles, dropping to perhaps 70 % for 2.5 micron particles, and 50 % for 1 micron particles. Addition of a second multiple cyclone in series with the first will allow for increased removal efficiency.

Note that the centrifugal force in, and, hence, efficiency of a cyclone increases with the gas flow rate through the cyclone. Thus, multiple cyclones on boilers are most effective at high boiler loads, where flue gas flow rates are highest, with collection efficiency decreasing at lower loads. Multiple cyclones have no moving parts, but do require regular cleaning to avoid plugging, and preventive maintenance to avoid leaks that would disrupt flow patterns and thus lower collection efficiency (USEPA 1999a; ICAC 2003).

##### **Flue Gas Conditioning**

Flue gas conditioning is used to modify the characteristics of the gas stream and particles to enhance particle removal in the primary collection device. It usually involves the use of chemicals that are added to the gas stream to improve the fly ash properties and electrical conditions in electrostatic precipitators. Gas conditioning for fabric filters and scrubbers consists of controlling the temperature or moisture content of the gas stream rather than chemical treatment.

For electrostatic precipitators, conditioning agents are added to adsorb on surface fly ash to reduce surface resistivity, adsorb on fly ash to change adhesion/cohesion properties, increase ultrafine particle concentration for space charge improvement, increase sparkover voltage of flue gas (reduce back corona), increase mean particle size, or decrease acid dew point in the flue gas. Common conditioning agents include sulfur trioxide, ammonia, ammonia compounds, organic amines, and dry alkali. Incremental increases in control efficiency are difficult to estimate but reportedly range up to 18 % for one system. (EPA 1998d; EPA 1999b; EPA 1999c)

### 5.3.1.2 Electrostatic Precipitators

Electrostatic precipitators, which have been used for particulate control since 1923, use electrical fields to remove particulate gas streams that are relatively easy to ionize, such as boiler flue gas. Because precipitators act only on the particulate to be removed, and only minimally hinder flue gas flow, they have very low pressure drop, and thus low energy requirements and operating costs. A typical electrostatic precipitation consists of a box that contains an array of negatively charged wires or rigid frame electrodes and positively grounded collection plates. Particulate-laden air passes through the box where high-voltage current is applied by electrodes that ionize the gas molecules. An intense electric field is maintained between the high-voltage discharge electrodes, typically wires or rigid frames, and the grounded collecting electrodes, typically plates. A corona discharge from the discharge electrodes ionizes the gas passing through the precipitator, and gas ions subsequently ionize fly ash (or other) particles. The electric field drives the negatively charged particles to the collecting electrodes. Periodically, the gas flow is diverted from a section of the collector plates, grounding the plates to remove the charge, and cleaning the plates, either by vibrating them with mechanical rappers or collecting dislodged particulate matter into collection hoppers for removal.

Particulates emitted during normal operation of large utility oil-fired boilers ( $> 100$  mmBtu/hr) are too fine to be collected efficiently by mechanical collectors, and in such cases, electrostatic precipitators are used. Up to 90 % removal efficiencies have been reported for these electrostatic precipitators in utility oil-fired boiler applications (EPA 1998c). Electrostatic precipitators offer high, fine particle removal efficiency at low-pressure drops and relatively low operating costs. However, the particulate matter collection efficiency of an electrostatic precipitator is a function of many factors; the most important of these factors includes particle resistivity, collection plate area, flue gas flow rate (particle residence time), flue gas temperature and humidity, and particle size distribution. The particulate matter removal efficiency can be adversely affected by changes in flow rate, particle size distribution and particle resistivity, and flue gas characteristics (Buonicore and Davis 1992).

#### Dry Electrostatic Precipitators

In a typical electrostatic precipitator, collecting plates are arranged parallel to the gas flow, normally 9 inches to 18 inches apart, with discharge electrodes between them. Most precipitators have 3 to 5 independent electrical sections, such as sets of discharge and collecting electrodes with independent power supplies, in series. Each independent section removes a fraction of the particulate in the gas stream. This arrangement allows the use of higher voltages in the first sections of the precipitator, where there is more particulate to be removed. Lower voltages must be used in the final, cleaner precipitator sections to avoid excessive sparking between the discharge and collecting electrodes. In a precipitator with only one electrical section, the power input would be limited to the input that would cause sparking at the precipitator exit, thus limiting the performance of the entire precipitator. Precipitator sectionalization has the added advantage that particles re-entrained in the flue gas stream by rapping may be collected in downstream sections of the precipitator, thus minimizing net rapping re-entrainment losses.

While several factors determine electrostatic precipitator removal efficiency, precipitator size is of paramount importance. Size determines treatment time—the longer a particle spends in the precipitator, the greater its chance of being collected, other things being equal. Precipitator size is also related to the specific collection area (SCA), the ratio of the surface area of the collection electrodes to the gas flow. Higher collection areas lead to better removal efficiencies. Collection areas normally are in the range of 200 to 800 ft<sup>2</sup> per 1000 actual cubic feet per minute (acmf). In order to achieve collection efficiencies of

99.5 %, specific collection areas of 350 to 400 ft<sup>2</sup> per 1000 acmf are typically used. Some older precipitators on utility boilers are small, with specific collection areas below 200 ft<sup>2</sup> per 1000 acmf and correspondingly short treatment times. Expansion of these precipitators, or their replacement with larger precipitators, can lead to greatly enhanced performance.

Maximizing electric field strength will maximize precipitator collection efficiency. Automatic voltage controllers are used to maintain electric field strengths as high as possible to ensure maximum particle charging and collection, consistent with preventing electrical breakdown of the gas and sparking between the discharge and collecting electrodes, which would extinguish the electric field. These controllers detect spark onset and maintain voltages just below the level at which sparking would occur. Factors limiting precipitator performance are flow non-uniformity and re-entrainment. More uniform flow will ensure low gas flow velocity and adequate treatment time paths through the precipitator. Attaining flow uniformity also will minimize "sneakage", or gas flows bypassing the electrical fields. Re-entrainment of collected particles may occur during rapping. Proper rapper design and timing will minimize re-entrainment. Maintenance of appropriate hopper ash levels and of flow uniformity will minimize re-entrainment of ash from the hoppers.

Another key determinant of electrostatic precipitator collection efficiency is the resistivity of the particles to be collected. Resistivity is the resistance of particles to the flow of electric current. Particles with resistivities in the range of 1.0E+07 to 1.0E+10 ohm-cm are amenable to collection with precipitators. These particles are easy to charge, and only slowly lose their charge once deposited on a collecting electrode. Particles with low resistivities (less than 1.0E+07 ohm-cm), on the other hand, lose their charge to a collecting electrode so rapidly that they tend not to adhere to the electrode, with the result that there will be high rapping re-entrainment losses. Carbon black is an example of a low resistivity material. Particles with high resistivity (greater than 1.0E+10 ohm-cm) can be difficult to remove with a precipitator; such particles are not easily charged, and thus are not easily collected. High-resistivity particles also form ash layers with very high voltage gradients on the collecting electrodes. Electrical breakdowns in these ash layers lead to injection of positively charged ions into the space between the discharge and collecting electrodes ("back corona"), thus reducing the charge on particles in this space and lowering collection efficiency. Fly ash from the combustion of low-sulfur coal typically has a high resistivity, and thus is difficult to collect.

Electrostatic precipitator overall (mass) collection efficiencies can exceed 99.9 %, and efficiencies in excess of 99.5 % are common for some applications. Precipitators with high overall collection efficiencies will have high collection efficiencies for particles of all sizes, so that excellent control of PM<sub>10</sub> and PM<sub>2.5</sub> will be achieved with well designed and operated electrostatic precipitators. Precipitator collection efficiencies will be somewhat lower for particles with diameters near 0.3 microns. The reason for a minimum in collection efficiency for 0.3 micron particles is that particle charge and the resistance of the gas to particle motion both increase with particle size. Near 0.3 microns, the particle charge is low enough and the resistance to particle motion is high enough that particles are collected relatively poorly. In practice, however, this effect means only that a precipitator with a 99.9 % overall mass collection efficiency will collect over 90 % of 0.3 micron particles, and over 97 % to 98 % of all 0 to 5 micron particles.

As noted above, older electrostatic precipitators may show poor performance. In addition to general deterioration of the precipitators, several design factors can lead to less-than-desired performance. These can include small size and consequent short treatment time and low specific collection area, non-uniform flow, and inadequate electrical control systems. Options for improving the performance of existing precipitators begin with simple rebuilds. These normally include the replacement of electrodes, rappers,

and other internal elements, and modernization of the precipitator power supply and control system. An upgraded control system allows for improved voltage control, so that the voltage in each field may be maintained at the highest level possible without sparking. Precipitator rebuilds also include improvements to the ductwork, casing, and flow devices to improve the flow distribution, and to seal leaks. Replacement of electrodes typically is accompanied by an increase in the spacing between collecting electrodes from 9 inches up to 12 or 18 inches. While using a wider plate spacing lowers specific collection area, the ability to use higher operating voltages without sparking increases collection efficiency enough to more than compensate for this change. Further performance improvements can be obtained by increasing precipitator size and specific collection area.

Some older, large utility boiler units have specific collection areas as low as 150 ft<sup>2</sup> per 1000 acmf; so increases to values near 400 ft<sup>2</sup> per 1000 acmf may be necessary in order to meet the new source performance level of 0.03 lb/mmBtu. Increasing the plate height may enhance the specific collection area and treatment time, allowing maximum use of the existing casing. On the other hand, there is a limit to the extent that plate height can be increased, as precipitators should be longer than they are wide for maximum performance. Better options for increasing treatment time and collection area are adding one or more electrical fields and increasing the length of the fields. Because these options require additional construction outside of the existing casing, they are more expensive. Finally, replacement of the precipitator with a new one is a last-resort option for improving collection efficiency.

### **Wet Electrostatic Precipitators**

The wet electrostatic precipitator is essentially a variation of the dry electrostatic precipitator. The differences are that a preconditioning step is used to provide cooling, gas absorption, and coarse particle removal; and a wetted collection surface is provided where liquid is used to continuously flush away collected particulate. Unlike dry electrostatic precipitators, which use rapping to remove particulate from the collecting electrodes, wet electrostatic precipitators use a water spray to remove this particulate. A typical wet configuration has (vertical) cylindrical collecting electrodes, with discharge electrodes located in the centers of the cylinders. Wet precipitators are useful in obtaining low opacities through the removal of acid gases and mists in addition to fine particulate. In addition, these devices have no rapping re-entrainment losses, and no back corona. Particle collection is achieved by introducing liquid droplets through spray nozzles located above the electrostatic field sections and the migration of charged particles and liquid droplets to the collection plates. The collected liquid droplets form a continuous downward-flowing film over the collection plates that removes collected particulate.

Wet electrostatic precipitators offer less potential for particulate matter buildup on collection plates than dry electrostatic precipitators. In a wet electrostatic precipitator, continuous washing prevents the buildup of an insulating layer of collected flyash. In the dry electrostatic precipitator rapping process, particulate emissions may result from the re-entrainment of rapped particles in the flue gas. The wet electrostatic precipitator collector cleaning process avoids this potential problem. The wet electrostatic precipitator also offers the potential for the collection of gaseous or condensable pollutants in addition to particulate removal. Wet electrostatic precipitator disadvantages include higher corrosion potential and higher capital and operating costs than dry electrostatic precipitators.



### 5.3.1.3 Fabric Filters

#### Baghouses

Fabric filter collectors "baghouses" are conceptually simple. By passing flue gas through a tightly woven fabric, particulate in the flue gas will be collected on the fabric by sieving and other mechanisms. The dust cake that forms on the filter from the collected particulate can contribute significantly to collection efficiency. Practical application of fabric filters requires the use of a large fabric area in order to avoid an unacceptable pressure drop across the fabric. To provide a large fabric area in a small space, the fabric is formed into cylindrical bags (hence, the term baghouse). Each bag may be 20 feet to 30 feet long, and 5 inches to 12 inches in diameter, and a baghouse for a 250 MW utility boiler may have 5000 separate bags with a total fabric area approaching 500,000 square feet. Groups of bags are placed in isolable compartments, to allow cleaning of the bags (see below), or to allow replacement of some of the bags without shutting down the entire baghouse. Baghouse size for a particular unit is determined by the choice of air-to-cloth ratio, or the ratio of airflow to cloth area, typically expressed in feet per minute (cubic feet per minute of flow divided by square feet of fabric area). The selection of air-to-cloth ratio depends on the particulate loading and characteristics, and the cleaning method used. High particulate loadings will require the use of a larger baghouse in order to avoid forming too heavy a dust cake, resulting in an excessive pressure drop.

Baghouses often are capable of 99.9 % removal efficiencies, and commonly can reduce utility boiler emissions to below 0.03 lb/mmBtu, and often to below 0.01 lb/mmBtu. Baghouse removal efficiency is relatively level across the particle size range, so that excellent control of  $PM_{10}$  and  $PM_{2.5}$  can be obtained.

Determinants of baghouse performance include the fabric chosen, the cleaning frequency and methods, and the particulate characteristics. Fabrics that will intercept a greater fraction of particulate can be chosen, and some fabrics are coated with a membrane with very fine openings for enhanced removal of submicron particulate. Such fabrics tend to be more expensive. Cleaning intensity and frequency are important variables in determining removal efficiency. Because the dust cake can provide a significant fraction of the fine particulate removal capability of a fabric, cleaning that is too frequent or too intense will lower the removal efficiency. On the other hand, if removal is too infrequent or too ineffective, then the baghouse pressure drop will become too high.

Two major baghouse types are used in utility applications. In a reverse-air baghouse, the flue gas flows upward through the inside of vertical bags, which open downward. The fly ash thus collects on the insides of the bags, and the gas flow keeps the bags inflated. To clean the bags, a compartment of the baghouse is taken offline, and the gas flow in this compartment reversed. This causes the bags to collapse, and collected dust to fall from the bags into hoppers. (Shaking or another method may be necessary to dislodge the dust from the bags.) The cleaning cycle in a reverse-air baghouse typically lasts about 3 minutes per compartment. Because reverse-air cleaning is gentle, reverse-air baghouses typically require a low air-to-cloth ratio of 2 ft/min. In a pulse-jet fabric filter, dirty air flows from the outside of the bags inward, and the bags are mounted on cages to keep them from collapsing. A reverse pulse of high-pressure air removes dust that collects on the outsides of the bags. This cleaning does not require isolation of the bags from the flue gas flow, and thus may be done online. Because pulse-jet cleaning is harsh, the bags remain relatively clean, so that a higher air-to-cloth ratio of 4 ft/min (that is, a smaller baghouse) may be used in utility applications.

Fabric filters are useful for collecting particles with resistivities either too low or too high for collection with electrostatic precipitators. Fabric filters therefore may be good candidates for collecting fly-ash

from low-sulfur coals or fly ash containing high levels of unburned carbon, which respectively have high and low resistivities, and, thus, are relatively difficult to collect with electrostatic precipitators. Adding a baghouse downstream from an existing electrostatic precipitator has been explored as a means of obtaining very low particulate emissions of 0.01 lb/mmBtu or less. Because the precipitator will remove the bulk of the particulate, the baghouse can be relatively small, with an air-to-cloth ratio of 8 ft/min or higher, and, thus, inexpensive. One embodiment of this concept is the use of a small pulse-jet fabric filter downstream of the precipitator, which has been patented by the Electric Power Research Institute (EPRI) and is known as a Compact Hybrid Particulate Collector (COHPAC). This fabric filter may be separate from the precipitator, as is being installed at a large utility plant in Texas, or may be installed into the last field of an electrostatic precipitator, as has been demonstrated at a plant in Alabama. This latter approach requires little space and relatively low capital expense.

Fabric filters have been applied widely to control particulate emissions from a variety of combustion units and industrial process equipment. Under proper conditions, fabric filters are capable of achieving very high PM<sub>10</sub> control efficiencies (greater than 99.9 %). A baghouse consists of several filtering elements (bags) and a bag cleaning system, all contained in a main shell structure equipped with dust hoppers. Particulate-laden gases are passed through the bags so that particles are retained on the fabric. This creates a filtering dust layer that is the basis of the performance of the fabric filter. The major fabrics used for bags for incinerator applications are woven and felted fiberglass and Teflon fluorocarbon materials. Typically, a baghouse is divided into compartments or sections, each containing several bags. In larger installations, an extra section is often provided to allow one compartment to be out of service for cleaning without affecting the overall efficiency of the fabric filter.

The two major design and operational parameters that govern baghouse performance are air-to-cloth ratio and pressure drop. The air-to-cloth ratio is the ratio of the actual volumetric gas flow rate (actual cubic feet per minute) to the surface area of the fabric media (square feet). In general, lower air-to-cloth ratios are used for the collection of fine particles. Smaller particles tend to become permanently trapped in the filter media, thereby clogging or blinding the filter media. As such, gas streams with fine particles require greater amounts of filter media for an equivalent volume of gas cleaned than for larger particle removal systems. The pressure drop across the filter media is a function of the face velocity of the gas stream through the filter and the combined resistance of the fabric and accumulated dust filter cake. Both the control efficiency and pressure drop across the filter surface increase as the dust layer builds up. Air flow will decrease if the pressure drop is too great. Therefore, in a baghouse, bags are cleaned periodically by reverse airflow, pulse-jet, or a shaker mechanism. The dust is collected below the filters in hoppers for disposal. To avoid operational problems and excessive power requirements, baghouses are generally operated with pressure drops of 6 inches to 8 inches of water column. With HEPA filters, when pressure drop becomes excessive the collector is taken offline and the filters are replaced.

The fabric filter airflow rate capacity can be varied widely with little effect on efficiency. This inherent flexibility permits an increase in capacity within reasonable limits by increasing the system fan horsepower. An oversized unit is more desirable than an undersized unit, because the dust loading and gas volume surge during many operations. A sudden increase in dust loading and possible volume increase will increase the outlet dust loading on other types of collectors but will not affect the performance of a fabric collector. Sporadic overloading can be readily accommodated by the collector, but a fabric filter should not be operated at wide variations from the equipment manufacturer's recommendations.

The particulate control efficiency of a fabric filter generally exceeds that of any other applicable control device. Collection efficiencies of baghouses may be more than 99 % (EPA 1998c). Results of utility

boiler studies done by the EPRI with pilot and full-scale equipment have shown that baghouses routinely achieve a clear stack and particulate collection efficiencies well in excess of 99.9 %.

Fabric filters have other advantages that make them suitable for controlling particulate emissions. For the size range of control devices under consideration, fabric filters use less energy than either scrubbers or electrostatic precipitators for equivalent outlet particulate concentrations. Fabric filters are efficient collectors of very fine emissions and are tolerant of fluctuations in the inlet particle size distribution (which affects electrostatic precipitators). Finally, fabric filters and electrostatic precipitators collect particulate emissions as a dry dust that is easier to handle or recycle than the wastewater and sludge collected from scrubbers.

General advantages that baghouses have over electrostatic precipitators are that:

- Baghouses have the potential for effective collection of submicron particles and a corresponding improvement in the capture of trace metals and organic compounds.
- The use of improved bag materials provides the potential flexibility to control collection to more stringent levels in the future.

Although fabric filtration systems exhibit high control efficiencies over a wide range of gas stream characteristics, their application has some inherent limitations. The most relevant deficiency of fabric filtration devices is the sensitivity of the filter media to gas stream temperature, moisture, and constituents in the gas stream that can blind or plug the media (reducing flow capacity) or destroy the structural components of the system through corrosion. In some cases, this limitation can be mitigated by proper preconditioning of the gas stream prior to its entry to the fabric filter.

#### **High-Efficiency Particulate Air Filters**

A HEPA filter is another type of fabric filter. The collection mechanism is identical to that of a baghouse. Collection efficiency is largely determined by fabric media selection. HEPA filters are traditionally designed to perform in the higher performance ranges of fabric filtration. There is a greater flexibility in media selection and system design because cleaning is not a part of system design. HEPA filters for many applications are used once and replaced. HEPA filters are widely used in "clean room" applications where high degrees of removal efficiency are required. HEPA filters are frequently used to protect carbon adsorption beds from contamination and to collect carbon particles that may be emitted from the carbon beds on the downstream side of a carbon adsorption system.

Upstream prefilters are normally used to protect HEPA filters. The prefilters operate with a low pressure drop ( $\Delta p < 0.65$  inches of water column) design and a collection efficiency anticipated to be in the 80 % to 85 % range. Like the HEPA filters, prefilters have to be replaced when they become loaded. For continuous processes, dual systems are normally installed to allow maintenance of one set of filters without taking the system offline. HEPA filters are best applied to situations where high collection efficiency of submicron particulate matter is required and typically are used for applications involving chemical, biological, or radioactive particulate matter.

#### **5.3.1.4 Wet Scrubbers**

Wet scrubbers are based on the collection of particles in liquid droplets, and scrubber design therefore is optimized for droplet creation. In venturi scrubbers, which are commonly used for particulate collection,

the scrubbing liquid and flue gases accelerate through a converging section of duct into a narrow throat, and then pass through the throat into a diverging section. In the throat, very high gas velocity shears the scrubbing liquid into a cloud of very fine droplets that collect particles. Increased pressure drop across the venturi leads to better droplet formation and particle collection, and pressure drops may exceed 30 inches of water in the most efficient units. Some scrubbers with lower pressure drops, down to about 5 inches of water, provide lower removal efficiencies that may be acceptable in some applications. Wet scrubbers designed for 85 % SO<sub>2</sub> removal can provide control of particulate emissions to below 0.10 lb/mmBtu, with removal efficiencies greater than 90 % for particles with diameters above 10 microns. Efficiencies for smaller particles will be significantly lower.

### Venturi Scrubbers

Venturi scrubbers are used to control particulate matter emissions for a wide variety of process applications, including incineration and mineral or chemical processing (Buonicore and Davis 1992). Scrubbing systems have also been installed on oil-fired boilers to control both sulfur oxides and particulate. These systems can achieve particulate control efficiencies of 50 % to 60 % (EPA 1998d). The EPA also reports that collection efficiencies range from 70 % to 99 % can be achieved for specific applications. However, these collection efficiencies may not be attainable for a large fraction of boiler flue gas particulate matter because it is not in the high removal efficiency range of aerodynamic diameters of approximately 0.5 to 5 micrometers (EPA 1999d). Venturi scrubbers use the kinetic energy of a moving gas stream to atomize a scrubbing liquid that, in turn, is used to contact and separate particulate matter from the flue gas.

A venturi scrubber consists of 4 sections: converger, throat, diverger, and scrubber liquid separator. During operation, liquid (either water or water with a caustic agent) is continually injected into the venturi scrubber at the entrance to the convergent section, the venturi throat, or both. As gases pass through the converging section of the venturi, they are accelerated. The high-velocity gas impacts the liquid injected into the venturi, thereby atomizing the scrubbing liquid. The combination of small liquid droplet size and high gas velocities increases liquid to particle contact, increasing the ability of the liquid to entrain particles and remove them from the gas stream. As gases exit the venturi throat, they pass through the diverging section, where the gas stream momentum is reduced, and some of the stream energy is converted back to system pressure. Not all of the pressure lost in the venturi is regained in the diverging section. The amount of system pressure lost is often referred to as pressure drop. The pressure drop is a measure of energy expended to remove particulate matter and the resulting removal efficiency.

Depending on the particle size distribution, particulate loading, and the required removal efficiency, venturi scrubber pressure drops usually range from 30 inches to 100 inches of water (Buonicore and Davis 1992). The venturi drop is affected by changes in gas flow rate. To account for flow rate changes, variable area throats are often used so that the pressure drop can be automatically adjusted as gas flow rates change. Venturi scrubbers, like other wet scrubbers, require the use of a demister to remove entrained moisture droplets from the flue gas. In addition to removing entrained moisture droplets, demisters are capable of removing solid particulate matter. Demisters capture particulates using a combination of 3 different mechanisms: interception, impaction, and Brownian motion diffusion (Buonicore and Davis 1992). Each mechanism operates more efficiently for a particular particle size.

Venturi scrubbers have historically been chosen over baghouses and electrostatic precipitators for relatively small combustion units. Venturi scrubbers have the general advantages of wet scrubbers (partial acid gas removal and low solids buildup), and lower capital costs, operating simplicity, and moderate maintenance. Venturi scrubber technology is relatively mature and has been used in numerous

applications under a variety of conditions—the technology is established, and its capabilities are well known. However, venturi scrubbers usually require high-pressure drops to achieve high particulate matter removal efficiencies. Higher-pressure drops result in higher operating costs and higher capital costs.

Even with high-pressure drops, venturi scrubbers may have trouble removing particles less than 0.5 micrometer in diameter, and consequently may have trouble achieving more restrictive particulate matter emission limits (Buonicore and Davis 1992). The particulates that typically penetrate the venturi scrubber are very fine particles (for example, condensable metals and organic matter). Also, for scrubbers, provisions have to be made to prevent entrainment of liquid into the exiting gas stream. Normally this is accomplished by adding louvered or mesh mist eliminators to capture entrained liquid droplets, adding to the system cost and complexity (Cooper and Alley 1994).

#### **Impingement Plate/Tray Tower Scrubbers**

An impingement plate scrubber is a vertical chamber with plates mounted horizontally inside a hollow shell. Impingement plate scrubbers operate as countercurrent particulate matter collection devices. The scrubbing liquid flows down the tower while the gas stream flows upward. Contact between the liquid and the particle-laden gas occurs on the plates. The plates are equipped with openings that allow the gas to pass through. Some plates are perforated or slotted, while more complex plates have valve-like openings.

The simplest impingement plate is the sieve plate, which has round perforations. In this type of scrubber, the scrubbing liquid flows over the plates and the gas flows through the holes. The gas velocity prevents the liquid from flowing down through the perforations. Gas-liquid particle contact is achieved within the froth generated by the gas passing through the liquid layer. Complex plates, such as bubble cap or baffle plates, introduce an additional means of collecting particulate matter. The bubble caps and baffles placed above the plate perforations force the gas to turn before escaping the layer of liquid. While the gas turns to avoid the obstacles, most particulate matter cannot turn, and is collected by impaction on the caps or baffles. Bubble caps and similar designs also prevent liquid from flowing down the perforations if the gas flow is reduced.

In all types of impingement plate scrubbers, the scrubbing liquid flows across each plate and down the inside of the tower onto the plate below. After the bottom plate, the liquid and collected particulate matter flow out of the bottom of the tower. Impingement plate scrubbers are usually designed to provide operator access to each tray, making them relatively easy to clean and maintain. Consequently, impingement plate scrubbers are more suitable for particulate matter collection than packed bed scrubbers. Impingement plate scrubbers can collect particles that are greater than 1 micrometer in diameter effectively, but many particles that are less than 1 micrometer in diameter will penetrate these devices (EPA 1998a).

#### **5.3.1.5 Incinerators**

Incinerators are seldom used as an add-on control device to remove only particulate matter. They are usually introduced when the gas stream has a high VOC content (EPA 1998d). If there is a significant quantity of soot (carbon particles from incomplete combustion of hydrocarbons), coke, or carbon residue to be destroyed in a gas stream, incineration is an option. Commercial incinerators are categorized as either thermal or catalytic, but the catalytic systems may encounter deactivation by coating or fouling problems in the presence of a significant amount of particulate matter.

#### 5.3.1.6 Combined Systems

For complex systems, a combination of control equipment may be used for pollution control. Frequently, the presence of water in the gas stream may interfere with the operation of fabric filters requiring additional gas stream conditioning equipment, for example, or necessitating the alteration of the temperature or composition of the gas stream to maximize removal efficiencies. Another common combination is the pretreatment of a gas stream with a cyclone, followed by a wet scrubber to capture and remove absorbed particles.

Combined systems are typically used for control of emissions of different pollutants or if the emissions from the process are significant because of quantity or potential toxicity. The typical combined system for a large fuel-fired plant might have a scrubber for sulfur oxides plus a particulate removal system. Although scrubbers can be highly efficient in the control of particulate matter, fabric filters have typically provided the highest level of control, followed closely by electrostatic precipitators. Typically a scrubber would provide acid gas cleaning with downstream particle removal.

The configuration of the combined system depends on the waste stream characteristics and the pollutants that need to be controlled. The pollutants in the waste stream dictate the scrubber system configuration design. The selection of the particle removal system is dependent on the gas stream leaving the scrubber. Excess moisture from the scrubbers or residual corrosive gases and particulate matter that could clog fabric filters are considerations in designing combined systems. The particulate control efficiency from a combined system is essentially equal to stand-alone particulate control systems. The combined system allows the use of particulate control devices that would otherwise be infeasible due to waste stream characteristics. An example would be the use of a scrubber/electrostatic precipitator combination in a highly acidic waste stream. The acidic waste stream would normally exclude the use of an electrostatic precipitator, but due to the use of the scrubber, the stream could be neutralized and not damage the electrostatic precipitator. This is also true in the case of fabric filtration: removal of gaseous constituents that would harm or clog filter media and damage housings makes combined systems feasible where stand-alone fabric filtration is not.

#### 5.3.1.7 Fuel Substitution and Source Reduction

The option of fuel substitution entails use of either natural gas or a fuel source that has a lower tendency to generate particulate matter in a combustion boiler. Use of ultra-low sulfur content distillate fuel oil for utility boiler combustion operation at the WTP, rather than a less expensive heavy or residual oil, was selected because of availability and logistical considerations.

The distillate fuel planned for use already has an inherently low potential for particulate matter formation because of its low ash and sulfur content. The primary task of reliably and safely providing high pressure steam power for the WTP is considered to be paramount and is oriented toward minimizing the overall risk to the public from treatment of the wastes. The primary mission of limiting possible releases and exposures supersedes other options.

#### 5.3.1.8 Lower Polluting Options

A lower pollution option was not analyzed for this system. Fuel-oil fired boilers were selected to safely and reliably deliver high pressure steam for the WTP in the early design phases of the project when it was decided that it presented the smallest overall risk to the public. Other options were either not feasible or

not safe. Emissions of the particulate matter will only last a finite time and will stop when WTP operations end after the inventory of waste is disposed.

### **5.3.2 Technical Feasibility Considerations**

As indicated previously, the analysis of technical feasibility of control options in this top-down BACT analysis will initially consider whether the control options have been installed and operated successfully on hazardous waste incinerators. In general, a commercially available control option will be presumed to be technically feasible for the WTP if the option has been or is soon to be deployed on the same or similar type of unit (that is, a fuel-oil fired boiler), barring a demonstration of unusual circumstances preventing the application of a control option. The control option under review is presumed to be technically feasible unless differences in the physical and chemical characteristics of the pollutant-bearing gas streams discharged from the emission units negatively affect the successful operation of the control option.

Because of differences in the grade of no. 2 fuel oil that is burned, not all boilers generate emission streams with the same or similar compositions. It is unlikely that any boiler flue gas streams will be the same from unit to unit. Depending on the boiler fuel composition, the design, and the operating conditions of the boiler, both major and minor differences can exist in particulate matter loading, particle size distribution, halogen content, sulfur and nitrogen oxides content, acid mist content, and metals and organic contents in boiler flue gases.

Technical approaches that can be eliminated because they are not feasible or relevant to particulate matter control for the small package boilers used for the WTP include: 1) HEPA filters, 2) incineration, 3) combined systems, and 4) fuel substitution and source reduction/lower polluting option strategies. Since HEPA filters are best applied to situations where high collection efficiency of submicron particulate matter is required, they are typically used for applications involving chemical, biological, or radioactive particulate matter. None of these apply to the simple combustion of fuel oil in a small package steam boiler; therefore, the use of HEPA filters is not considered applicable or feasible. Incineration is not feasible because it would only be used if it were needed to remove volatile organics, which are not present in the flue gases. Furthermore, incineration would increase emissions of combustion pollutants, including nitrogen oxide. Combined systems are not feasible because they do not offer any improvement in pollution control efficiency over individual control equipment units. The pretreatment of flue gases whether done by chemical or physical means, would only be applied for a single particulate matter control device. Fuel substitution and source reduction/lower pollution options are not viable or feasible options for the WTP project, based on the primary task of reliably and safely providing steam.

### **5.3.3 Control Technology Hierarchy**

The hierarchy of technically feasible particulate matter control technologies (from best to worst), based on the discussions of particulate matter control options presented previously, is listed in Table 5-4. This hierarchy provides a general indication of the capabilities of technically feasible control options applicable to the fuel-oil fired boilers and other particulate emitting processes. The hierarchy examines control options as individual units, but does not include the large number of possible options if one were to combine individual control options into a single gas treatment train (for example, the combination of baghouse, electrostatic precipitator, and wet scrubber). Evaluation of other emission control systems using combined technologies indicates that these systems are able to meet the same range of performance as stand-alone applications of these technologies. For example, a baghouse downstream from a wet scrubber would generally appear to perform within the expected range for other installed baghouses. Although the upstream scrubbers may be effective in particulate removal, their major benefit to combined

systems is to remove acid gases and other contaminants that would prove destructive to an electrostatic precipitator or baghouse.

### **5.3.4 Energy, Economic, and Environmental Impacts**

Although potential differences in energy, economic, and environmental impacts between the control options in Table 5-5, Table 5-6, and Table 5-7 exist, these differences are not believed to be significant enough to select any control option as preferred over another. As shown in Table 5-3, however, the proposed WTP particulate emission rate of 0.020 lb/mmBtu heat input is the top level of particulate control that has ever been established for small package boilers under PSD-BACT or other state regulatory requirements.

The energy and economic impacts of the ranked control options are summarized in Table 5-5 and Table 5-6, respectively. The economic impact summary clearly shows that the cost of any viable options are an order of magnitude or more in excess of those ordinarily used for EPA's cost effectiveness parameters. A vendor quote for a baghouse system for particulate control of the boiler system indicated an installed capital cost of \$1,293,332 to control particulate emissions from the 6 boilers planned for use at the WTP (RJM-Beaumont 2003).

Table 5-7 summarizes the potential environmental impacts of the control options identified in Table 5-4. Environmental impacts are discussed in terms of solid waste, liquid waste, and air emission components. Any solid and hazardous wastes generated from a boiler pollution control system operation will have to be disposed of in accordance with applicable regulations. Industrial wastewater and any liquid wastes generated by a wet control system will have to be recycled or disposed of. It is not anticipated that any toxic air pollutants or, to a lesser degree, condensable organics that are attributable to the pollution control systems would be released to the atmosphere. Although the aim of particulate control equipment is not to control acid gases or acid mists, the potential impacts of acid gas and acid mist emissions are included for completeness.

### **5.3.5 Selection of Proposed BACT**

For the emissions of particulate matter (assumed to be all  $PM_{10}$ ) from the steam boiler plant, the best available control technology is good combustion practices and design and a particulate emission limit of 0.020 lb/mmBtu. As can be seen in Table 5-3, this emission limit for the WTP boilers is more stringent than any comparable fuel-oil fired boiler.

It should be noted that the EPA data on particle size distribution of particulate matter emissions from fuel-oil fired boilers shows that 50 % of the particulates are greater than 10 micrometers in diameter. This corresponds to  $0.5 \times 18.7$  US tons per year  $\times (2.0/3.3) = 5.67$  US tons per year. The (2.0/3.3) ratio takes into account the fact that the particle size distribution data is only for the filterable particulate, totaling 2.0 lbs/1000 gal of no. 2 fuel oil. The condensable particulate contributes 1.3 lbs/1000 gal (EPA 1998c), and that fraction would most likely be present as a gas, and, therefore, a part of the total fraction that is less than 10 micrometers in diameter. If this material were not included in the total for  $PM_{10}$  emissions, the total facility emissions would be close to the significance threshold for PSD analysis, that is, 25.01 US tons per year (WTP, plant-wide) - 5.67 US tons per year = 19.34 US tons per year. The significance threshold is 15 US tons per year for  $PM_{10}$ . This shows that particulate emissions from the facility that are regulated under PSD have been kept to a minimum in the proposed design.



Regarding control systems to further limit particulate emissions from the oil-fired boilers which are the main source of particulate matter for the WTP project, the evaluation of options shows that the cost of any possible options are an order of magnitude or more above those ordinarily used for EPA's cost effectiveness parameter for each option considered.

One vendor quote for a baghouse system for particulate control of the boiler system indicated an installed capital cost of \$1,293,332 to control particulate emissions from the 6 boilers planned for use at the WTP (RJM-Beaumont 2003). That capital cost (see Appendix C, Table C-10) has been used to formulate an annualized cost effectiveness summary for the installation and operation of a baghouse system for the steam boilers. Results of that analysis are given in Appendix C, Table C-11, and the annualized cost was found to be \$38,096 per US ton per year of particulate matter; this is within the range of the cost effectiveness derived from EPA data: \$20,250 to \$131,630 per US ton per year, as applied to the WTP for the boilers. It is clearly well above the normal range of baghouse removal cost effectiveness of \$42 to \$266 per US ton per year of particulate (see Table 5-6).

## **5.4 PM BACT for the Auxiliary and Support Systems**

### **5.4.1 PM BACT for Standby Diesel-Fired Generators**

Three backup diesel generators will be used for the WTP to provide electrical power in the event of the loss of site power. Three of these generators will be rated at 3950 bhp (2500 KW) and 2 will be rated at 5530 bhp (3500 KW). Each generator will be tested every 2 weeks for 6 hours, and there may be as much as one additional 8-hour run per year in the event of the loss of site power to allow the facility to be safely shut down. The maximum potential operating period for each generator is, therefore, 164 hours of operation per year.

In addition, 2 fire pumps will each be powered by 300 bhp (474 KW) diesel-fired engines, less than one-tenth the size of the generator engines. Each engine is expected to be operated approximately 110 hours per year. Total particulate emissions are estimated to be 0.02 US tons per year (40 lbs/yr).

For the purposes of this analysis, all particulate matter produced by the generator engines has been assumed to be  $PM_{10}$ .

#### **5.4.1.1 Identification of Control Technology Options**

This section describes the various techniques that may be used to control  $PM_{10}$  emissions from backup diesel-fired engines. In accordance with EPA BACT guidance, the control options considered should have a practical potential for application to the emissions unit identified.

A list of potential candidates for consideration as BACT for particulate matter control has been developed. EPA's RACT/BACT/LAER clearinghouse, pollution control equipment vendor information, and relevant technical literature were reviewed. In addition, information was received from discussions with regulatory agency and control equipment vendor personnel. Particulate matter control approaches for consideration as BACT for the WTP backup generators include the following:

- Control during combustion processes
- Control using post-combustion reduction technologies

### **Combustion Processes**

The formation of PM<sub>10</sub> within the backup diesel generator engines can be limited through the use of fuel with lower sulfur content. In addition, following good combustion engineering practices can limit emissions, which include adherence to the diesel engine manufacturer's specifications for operation, maintenance, and combustion control.

### **Post-Combustion Reduction Technologies**

Additional control of PM<sub>10</sub> emissions from the backup engines can be achieved through the use of post-combustion reduction technologies. The majority of PM<sub>10</sub> emission control technologies for diesel engines have been developed for mobile sources. However, some of these control technologies have recently also been applied to stationary sources. The following is a list of add-on PM<sub>10</sub> control technologies applicable to stationary sources:

- Diesel oxidation catalyst (DOC)
- Diesel particulate filters (DPFs)
- NO<sub>x</sub>TECH emission control system (NO<sub>x</sub>TECH)
- Diesel oxidation catalyst with crankcase vent filtration (DOC with CCVF)

Table 5-8 provides data on demonstrated diesel-fired engine control technologies. Table 5-9 provides a summary of the advantages and disadvantages of particulate abatement technologies. Table 5-10 and Table 5-11 provide a brief summary of descriptions, ranking, and applicability discussions for control techniques. DOC with CCVF is considered a transferable technology because it is currently only commercially available for mobile sources, but has the potential to be applied to stationary sources as well.

#### **5.4.1.2 Description of PM Emissions Control Technologies**

The following summary is general and intended to provide a broad overview of these technologies.

##### **Diesel Oxidation Catalysts**

DOCs are typically flow-through designs, separately as a converter or in the mufflers of diesel engines, composed of a catalyst wash coat (typically a base metal oxide and precious metal), and a ceramic or metallic substrate. The catalyst interacts with the exhaust as it passes through the converter and causes the particulate to burn at normal exhaust temperature. DOCs are also effective to control the gaseous hydrocarbons (HC) and CO emissions.

##### **Diesel Oxidation Catalyst with Crankcase Vent Filtration**

The DOC with CCVF system combines the technology of the DOC and adds a crankcase vent emissions filtration system. The crankcase vent filtration is a 2-stage filtration system that eliminates 100 % of the crankcase PM emissions. The filter system is designed to collect, coalesce, and return the emitted lube oil to the engine's sump. The filtered gases are then returned to the intake system, while balancing the differential pressures involved.

### **Diesel Particulate Filters**

A typical DPF consists of a filter system designed to collect particulate emissions while allowing exhaust gases to pass through the system. Over time, particulate matter generated by a diesel engine will fill up and plug a filter. In order to dispose of the trapped particulate, the filter oxidizes (or burns) the particulate matter during regular engine operations, thus regenerating itself.

### **NO<sub>x</sub>TECH Emission Control System**

The NO<sub>x</sub>TECH emission control system is used to control emissions of NO<sub>x</sub>, VOC, CO, and PM from diesel engines. This system replaces conventional exhaust silencers with a reaction chamber that operates at temperatures in the range of 1400 °F to 1500 °F. Diesel fuel is combusted to control temperature, and a nonhazardous liquid chemical is injected to remove NO<sub>x</sub>. The unique temperature control substantially removes NO<sub>x</sub>, CO, and PM.

#### **5.4.1.3 Demonstrated Technologies**

### **Diesel Oxidation Catalyst**

DOC uses a catalyst and oxygen to reduce CO, HC, and the soluble organic fraction (SOF) of diesel particulate matter emissions from diesel exhaust. Through catalytic oxidation, CO, HC, and SOF are converted into carbon dioxide and water. Hydrocarbon traps (zeolites) and sulfate suppressants can be incorporated into the DOC to increase reduction efficiency. Hydrocarbon traps increase the removal efficiency of HC at lower exhaust temperatures and sulfate suppressants reduce the generation of sulfates at higher exhaust temperatures. This technology is available for stationary and portable diesel engines between 4 horsepower and 5000 horsepower and can be retrofitted to existing equipment.

**Advantages - DOC:** DOCs have the ability to reduce not only the soluble organic fraction of diesel particulate matter, but also carbon monoxide and hydrocarbon emissions.

**Disadvantages - DOC:** The catalytic oxidation process may cause the formation of sulfates at high temperature. Depending on the exhaust temperature and the sulfur content of the fuel, the increase in sulfate particles may offset the reductions in SOF emissions. The use of a diesel fuel with a ultra-low sulfur content is recommended to reduce the formation of sulfates.

### **Diesel Particulate Filters**

Diesel particulate filters are used to reduce particulate matter, carbon monoxide, and hydrocarbon emissions from diesel exhaust through filtration and catalytic oxidation. There are 2 types of particulate filters: passive and active. Most passive DPFs consists of ceramic wall-flow monoliths, which physically capture diesel particulate matter. The monoliths are generally coated with a precious metal catalyst that oxidizes the diesel particulates at common engine exhaust temperature. This oxidation process is called regeneration, since it allows the cleaning of the filter during hot duty cycle operations. In active filters the regeneration temperature is achieved using an external heat source, typically an electric or other heat source, to increase oxidation in the filter. Precious metals are also used as a catalyst to lower the regeneration temperature in active DPFs. Most DPFs are passive self-regenerating filter systems that collect particulate matter and oxidize it when the exhaust temperatures are above 530 °F. Typically, DPFs provides over 90 % reduction in diesel particulate matter emissions and total elimination of black

smoke. This technology is available for stationary and mobile diesel engines and can be retrofitted to existing equipment.

**Advantages - DPF:** DPFs have the ability to reduce not only particulate emissions from diesel exhaust, but also carbon monoxide and hydrocarbon emissions.

- **Active Diesel Particulate Filters (A-DPFs)**

A-DPFs are specifically designed for use with intermittently operated engines such as emergency standby generators and fire pumps, and are available for first-fit and retrofit applications. They use an efficient, low-power electric heater to oxidize collected PM after engine shutdown. On shutdown, the electric heater automatically begins a new regeneration cycle, preparing the engine for a clean startup. A-DPF systems do not appear to cause any additional engine wear or affect normal vehicle maintenance. Maintenance of the system itself should be minimal, because manufacturers are designing systems to minimize maintenance requirements during the useful life of the system.

- **Passive Diesel Particulate Filters (P-DPFs)**

P-DPFs oxidize PM during normal engine use at common exhaust temperatures through a process called self-regeneration; therefore, no external heat source or additional power is necessary.

**Disadvantages - DPF:** If high sulfur fuels are used, the catalyst may generate sulfates at high exhaust temperatures. In this case, the increase in sulfate particles may offset a portion of the filter capability of reducing particulate emissions from diesel exhaust. Diesel fuel with a very low sulfur content (sulfur content of less than 50 ppm) is recommended to maximize the emission reduction capability of this technology.

- **A-DPFs**

Some EPA testing has shown that A-DPFs may cause a slight loss in power of the engine.

- **P-DPFs**

In applications where the exhaust temperatures are too low, or if high temperatures occur only for very short periods, the filter may cause excessive back-pressure. In extreme cases, clogging of the filter may occur. Applications with higher exhaust temperatures and longer operating time allow a better regeneration of the filter, accumulate less soot in the filter, and have lower back-pressure.

### **NO<sub>x</sub>TECH Emission Control System**

The NO<sub>x</sub>TECH emission control system is a muffler-sized reactor that reduces carbon monoxide, hydrocarbons, and particulate matter through non-catalytic oxidation, similar to an afterburner. The engine exhaust is heated to a very high temperature (1400 °F to 1550 °F) in the reactor by introducing fuel to the exhaust stream. The high temperature environment oxidizes the particulate matter, carbon monoxide, and hydrocarbon emissions. A urea injection system can be added to reduce NO<sub>x</sub> emissions. The NO<sub>x</sub>TECH system is available for use on stationary and portable internal combustion engines. However, the application of this technology on standby generator sets is not effective, since the NO<sub>x</sub>TECH system cannot reduce particulate matter to low levels on these engines.

**Advantages - NO<sub>x</sub>TECH:** The use of low sulfur diesel fuel is not required for the NO<sub>x</sub>TECH system, since this product can operate effectively with fuels at higher sulfur levels. In addition to reducing diesel

particulate matter, this technology can also reduce carbon monoxide by 50 %, hydrocarbons by 60 % to 95 %, and nitrogen oxides emissions by 90 % to 95 % (with urea injection).

**Disadvantages - NO<sub>x</sub> TECH:** Where a urea system is added to reduce NO<sub>x</sub> emissions, any unreacted urea will be emitted as ammonia. Ammonia is not a federal hazardous air pollutant; however, it does have acute and chronic non-cancer health effects. Based on source test results, ammonia slip levels are controlled to below 2 ppm.

#### **5.4.1.4 Transferable Technologies**

The DOC with CCVF has been identified as a potentially transferable technology. DOC with CCVF technology has been successfully used in mobile source equipment, but has not been tested yet on stationary sources or generator sets with a large capacity. The following discussion presents the diesel oxidation catalyst with a crankcase vent filtration system.

##### **Diesel Oxidation Catalyst with Crankcase Vent Filtration**

DOC with CCVF controls PM emissions up to 50 % when applied to on-road and off-road vehicles. The California Air Resources Board (CARB) has certified DOC with CCV for use on mobile sources. The DOC with CCVF has been approved to meet CARB Level 1 requirements for reducing PM emissions from diesel-fired vehicles, which include PM emissions reductions of between 25 % and 85 %.

**Advantages – DOC with CCVF:** Increases the PM emissions removal potential to 50 % with the addition of the crankcase vent filtration system. The DOC with CCVF is cost-effective and operates effectively with any type of diesel fuel. The replaceable filter life is designed to coincide with the manufacturer's oil change interval or to occur every 500 hours, so limited additional maintenance is required. The system eliminates 100 % of the crankcase emissions.

**Disadvantages – DOC with CCVF:** This equipment has only been tested and certified by CARB on mobile sources. The technology has had limited testing on smaller industrial engines.

#### **5.4.1.5 Lower Polluting Options**

Ultra-low sulfur diesel fuel was analyzed for this system. Ultra-low sulfur diesel fuel will be easily available for use at the WTP. A supply, distribution, and storage network will be established prior to operation of the WTP. DPFs require the use of ultra-low sulfur diesel fuel (30 ppm or 0.003% by weight sulfur content) to achieve maximum PM reduction and minimal maintenance of the filter. Using ultra-low diesel fuel produces less PM, and sulfur oxides emissions than using low-sulfur diesel (500 ppm or 0.05% by weight sulfur content).

Biodiesel is a clean-burning fuel for diesel compression-ignition engines, derived from animal fats or vegetable oils such as soybean oil. Biodiesel has no sulfur or aromatic compounds and pollutes significantly less than diesel no. 2. Biodiesel can be blended with petroleum diesel and can be used in any unmodified diesel engine at any mixture ratio. B20 refers to blends of 20 % biodiesel (80 % diesel) and B100 refers to neat or 100 % biodiesel. Compared to diesel no. 2, the B20 blend can reduce an additional 8 % of particulate matter. However, due to limited production, shipping costs, and fueling infrastructure, biodiesel is expensive and difficult to acquire in large quantities at relatively remote locations such as Hanford.

#### 5.4.1.6 Technical Feasibility Considerations

The control techniques that are feasible include DOC and DPFs. Other technologies are not proven to reduce PM on standby stationary sources, as shown in Table 5-8.

#### 5.4.1.7 Control Technology Hierarchy

The available BACT control technologies for the standby diesel-fired engines include DOCs and DPFs. These techniques are ranked in Table 5-12 on the basis of the reported EPA and manufacturer PM removal.

#### 5.4.1.8 Energy, Economic, and Environmental Impacts

DOCs and DPFs are available to be customized for standby diesel-fired engines based on specific engine parameters and characteristics. There are no significant environmental or energy impacts associated with the use of such technology. There is a significant economic impact associated with the purchase of either a DOC or DPF due to the small amount of PM emissions associated with the standby diesel-fired engines. The following cost analysis was completed for the standby generators because they represent 98 % of the emissions from the standby diesel-fired engines. Fire pump control options were eliminated based on the large economic impact of reducing 0.02 US tons per year of PM.

##### 5.4.1.8.1 Diesel Particulate Filter Cost Estimate

The cost for a DPF ranges from \$30 to \$50 per bhp, depending on the application. This includes the price for both P-DPF and A-DPF. This would place the installed capital cost for adding DPFs to the 5 standby generators at \$450,300 to \$750,500. The following annualized economic impact is based on \$30 per bhp. The result shown in Appendix C, Table C-9 demonstrates that the annual cost of removal of 1 US ton of PM is estimated to be \$92,990, and this is considered to be well in excess of any cost-effective benefit guidelines. The reason, as in the case of the DOC, is that the annual emissions of particulate matter are relatively low and the cost of the particulate control system is relatively high.

##### 5.4.1.8.2 Diesel Oxidation Catalyst Cost Estimate

The cost of a DOC for the standby generators at the WTP is approximately \$30,000 per generator. This places the capital cost for adding DOCs to the 3 standby generators at \$90,000. Assuming the DOCs would last at least 10 years, the annualized cost is \$12,814. Because the control efficiency of DOC is only 20 %, applying DOCs to the generators would decrease PM emissions by 0.20 US tons per year. Without taking any operating or maintenance costs of the equipment into consideration, the total annualized cost per US ton of PM removed is \$38,442. This result is considered to be well in excess of any cost-effective benefit guidelines. The reason is that the annual emissions of particulate matter are relatively low and the cost of the particulate control system is relatively high.

#### 5.4.1.9 Selection of Proposed BACT for Standby Diesel-Fired Engines and Generators

None of the technically feasible control technologies are also economically feasible to be considered BACT. Limiting the hours of operation is proposed as BACT for the standby diesel-fired generator and fire pump engines. Because of the limited hours of operation per year, the emission from the standby generators is only 0.7 US tons per year, and the emission from the fire pump is only 0.01 US tons per year. Particulate matter and other emissions from the generators will be limited by restricting the hours of

testing to meet the minimum requirements. Finally, good combustion engineering practices will be followed, which include adherence to the diesel engine manufacturer's specification for operation, maintenance, and combustion control. Specified combustion feed gas ratios (including the fuel-to-air ratio), monitoring, and startup/shutdown procedures will be followed to maximize combustion efficiency and minimize discharge of pollutants into the atmosphere.

#### **5.4.2 PM BACT for Glass Former Facility**

The BACT for the glass former facility is considered to be the use of baghouses with 99.9 % control efficiency. PM emissions from the glass former facility primarily come from the loading and unloading of the material used in the glass formers mixture. Sodium carbonate is an element material of the glass former blend. Sodium carbonate has an EPA established emission factor and process control information which is identified in section 8.12 of the EPA's AP-42, *Compilation of Air Pollution Emission Factors* (EPA 1993). Therefore, sodium carbonate is the representative component of the mixture of glass formers used in the PM BACT consideration. A nominal control efficiency of 99.9 % is achievable when a baghouse is used to control the PM emissions from storage, loading and loading operations of sodium carbonate.

The glass former facility at the WTP will have baghouses for the storage silos and the blending silos for controlling PM emissions, thus reducing the PM emissions from the glass former facility to an insignificant 0.05 US tons per year. There are not any control measures that will reduce these nominal emissions any further.

#### **5.5 Summary of Proposed BACT for PM Emissions Control for the WTP**

Table 5-13 summarizes the proposed PM BACT.

**Table 5-1 BACT Control Technology Screening for WTP Process Streams**

Control	Category	Description	Media (being treated)		Screening Results	Comments
			Liquid	Solid		
1	Filter	Baghouse (Fabric Filter)		PM	Eliminated	Not applicable for hot cell use; difficult to adapt technology to remote operations due to large space requirement (multiple filter bags) and frequent bag changeout to maintain efficiency
2	Filter	Prefilter (Roughing Filter)		PM	Applicable	
3	Filter	High-Efficiency Metal Filter (HEMF)	Aerosol	PM	Eliminated	No existing long-term, large-scale applications; free liquids with dissolved acid gases must be excluded for contact with the filters; high initial cost; repetitive cleaning efficiency not demonstrated
4	Filter	High-Efficiency Porous Ceramic Filter	Aerosol	PM	Eliminated - redundant	Included under high-efficiency metal filter
5	Filter	High-Efficiency Particulate Air (HEPA) Filters	Aerosol	PM	Applicable	
6	Filter	Ultra-Low Penetration Air (ULPA) / Very Large-Scale Integration (VLSI) Filter		PM	Eliminated	Not applicable for hot cell use; frequent changing of filter media necessary to maintain efficiency; primarily applicable for medical and electronic clean room applications
7	Filter	Deep Bed Sand Filter	Aerosol	PM	Eliminated	Not applicable for hot cell use; very large space requirement; bed channeling can reduce efficiency and require changeout of large quantity of filter media; significant decommissioning and demolition impacts for large vault installations
8	Filter, Mist Eliminator	Deep Bed Glass Fiber Filter		PM	Applicable	
9	Mist Elim.	High-Efficiency Mist Eliminator (HEME)	Aerosol	PM	Applicable	



**Table 5-1 BACT Control Technology Screening for WTP Process Streams**

Control	Category	Description	Media (being treated)		Screening Results	Comments
			Liquid	Solid		
10	Mist Elim.	Standard Mist Eliminators	Aerosol	PM	Applicable	
11	Precipitator	Dry Electrostatic Precipitator (ESP)		PM	Applicable	
12	Precipitator	Wet Electrostatic Precipitator (WESP)	Aerosol	PM	Applicable	
13	Scrubber	Ejector Venturi Scrubber (EVS)	Aerosol	PM	Applicable	
14	Scrubber	Hydrosonic Air Atomized Scrubber (AAS)	Aerosol	PM	Eliminated - redundant	Included under hydrosonic scrubbers (HSS)
15	Scrubber	Hydrosonic Scrubbers (HSS)	Aerosol	PM	Applicable	
16	Scrubber	Hydrosonic Steam Atomized Scrubber (SAS)	Aerosol	PM	Eliminated - redundant	Included under hydrosonic scrubbers (HSS)
17	Scrubber	Impingement Scrubber		PM	Eliminated - redundant	Included under impingement-plate/tray tower scrubber
18	Scrubber	Impingement-Plate / Tray Tower Scrubber		PM	Eliminated	Not applicable for hot cell use; remote operations difficult due to frequent plugging and corrosion of trays/plates; not effective for submicron particulate removal
19	Scrubber	Mechanically-Aided Scrubber		PM	Eliminated	Not applicable for hot cell use; remote operations difficult due to corrosion and problems with mechanical/moving parts; not effective for submicron particulate removal
20	Scrubber	Packed-Bed / Packed-Tower Wet Scrubber		PM	Applicable	
21	Scrubber	Spray Tower		PM	Eliminated - redundant	Included under spray-chamber/spray-tower wet scrubber

**Table 5-1 BACT Control Technology Screening for WTP Process Streams**

Control	Category	Description	Media (being treated)		Screening Results	Comments
			Liquid	Solid		
22	Scrubber	Spray-Chamber/Spray-Tower Wet Scrubber		PM	Applicable	
23	Scrubber	Submerged Bed Scrubber (SBS)	Aerosol	PM	Applicable	
24	Scrubber	Tray Tower		PM	Eliminated - redundant	Included under impingement-plate/tray tower scrubber
25	Scrubber	Cyclonic Wet Scrubbers		PM	Applicable	
26	Separator	Multiple Cyclones (Multiclones)		PM	Applicable	
27	Separator	Reverse-Flow Cyclone Collector		PM	Applicable	

**Table 5-2      BACT Technology Ranking by Effectiveness for Control of Particulates for WTP Process Streams**

<b>Ranking</b>	<b>Control Technology</b>	<b>Average Removal Efficiency <sup>a</sup></b>
1	High-Efficiency Particulate Air (HEPA) Filter	99.95 %
2	Dry Electrostatic Precipitator (ESP)	99.45 %
2	Wet Electrostatic Precipitator (WESP)	99.45 %
3	High-Efficiency Porous Ceramic Filter	99 %
3	Hydrosonic Scrubber (HSS)	99 %
4	High-Efficiency Mist Eliminator (HEME)	97 %
5	Deep Bed Glass Fiber Filter	95.75 %
6	Multiple Cyclones (Multiclones)	89.5 %
7	Reverse-Flow Cyclone Collector	85 %
8	Spray-Chamber/Spray-Tower Wet Scrubber	84.5 %
8	Ejector Venturi Scrubber (EVS)	84.5 %
9	Submerged Bed Scrubber (SBS)	80 %
9	Standard Mist Eliminators	80 %
9	Prefilter (Roughing Filter)	80 %
10	Packed-Bed/Packed-Tower Wet Scrubber	72.5 %
11	Cyclonic Wet Scrubbers	60 %

<sup>a</sup> Removal efficiencies represent the average removal efficiencies documented in the literature. See 24590-WTP-RPT-ENV-01-004 for a list of the literature sources.

**24590-WTP-RPT-ENV-01-007, Rev 1**  
**Prevention of Significant Deterioration Application for**  
**Hanford Tank Waste Treatment and Immobilization Plant**

**Table 5-3      Compilation of Facility Emission Limits for Boilers Firing #2 Diesel**

Source Date	Documentation, RACT/BACT/LAER Clearinghouse Identification	Boiler Rating mmBtu/hr	Particulate Matter Emission Limit	Control Technology/ Basis
EPA AP-42	Table 1.3-1 Table 1.3-2	< 100	0.0143 lb/MMBtu filterable 0.00929 lb/mmBtu condensible 0.0236 total lb/mmBtu	Good combustion practices and design
EPA	40 CFR 60.42	> 30	< 20 % Opacity	New Source Performance Standard
	WTP	50.2 each (6 boilers)	0.020 lb/mmBtu	BACT-PSD
4/3/96	Mid-Gerogia Cogen., GA-0063	60	0.028 lb/mmBtu	Complete Combustion, BACT-PSD
1/28/99	Bates Mill Complex, (formerly WGP, Incorporated, ME-0029)	29.3 each (2 boilers)	0.03 lb/mmBtu (1,000,000 gal. no. 2 fuel oil per yr) PM: 4.2 US tons per year	ME Chapter 100 Air Regulations BPT = Best Practical Treatment  BACT-ESP or baghouse deemed not cost effective
9/30/93	Gordonsville Energy L.P., VA-0202	22	0.03 lb/mmBtu (0.6600 lb/hr)	Fuel Spec: Clean Burning Fuel, NSPS
10/24/01	AES RED OAK LLC, NJ-0036	99	0.040 lb/mmBtu	Limited Use BACT-PSD
4/14/93	Black Hills Power and Light Co., WY-0046	30.76	0.040 lb/mmBtu	Other- Startup operation only
1/1/98	Proctor & Gamble Paper Prod., MO-0051	50 each (3 boilers)	0.050 lb/mmBtu	BACT-PSD
5/29/97	Toyota Motor USA, Inc., KY-0068	96	0.100 lb/mmBtu	Fabric Filter, BACT-PSD
1/14/97	Merck-Rahway Plant, NJ-0045	99.5 each (2 boilers)	0.140 lb/mmBtu (3,987,183 gal. no. 2 fuel oil per yr)	Plant-wide Emission Limits, BACT-PSD
7/9/98	Archer Daniels Midland Co., ND-0018	13 28	0.200 lb/mmBtu 0.100 lb/mmBtu	BACT-PSD BACT-PSD

**24590-WTP-RPT-ENV-01-007, Rev 1**  
**Prevention of Significant Deterioration Application for**  
**Hanford Tank Waste Treatment and Immobilization Plant**

**Table 5-3      Compilation of Facility Emission Limits for Boilers Firing #2 Diesel**

<b>Source Date</b>	<b>Documentation, RACT/BACT/LAER Clearinghouse Identification</b>	<b>Boiler Rating mmBtu/hr</b>	<b>Particulate Matter Emission Limit</b>	<b>Control Technology/ Basis</b>
10/26/99	OMYA Inc., VT-0016 Class I area impacts	24	0.35 lb/mmBtu The application of additional PM control cannot be justified.	Low sulfur fuel, good operating practice, MSER = most stringent emission rate
9/21/93	Ringier America, Inc., GA-0071	60 each (2 boilers)	NONE < 20 % Opacity	GA Rule 391-3-1-.02(2)(D), not subject to PSD review

**Table 5-4 Hierarchy of Potential Control Efficiencies <sup>a</sup> for Technically Feasible Particulate Matter Control Equipment**

Control Equipment	Control Efficiency Range (%)
Fabric Filter (Baghouse or HEPA)	99 to 99.9
Dry Electrostatic Precipitator (ESP)	90 to 99
Wet Electrostatic Precipitator (WESP)	90 to 99
Impingement-Plate/Tray Tower Scrubber	50 to 99
Multiple Cyclones	70 to 90
Venturi Scrubbers	50 to 60

a Removal efficiencies are very strong functions of particle size distribution and design properties of the control system, so these quantitative values are given just to allow approximate ranking of the control technology options.

**Table 5-5 Summary of Potential Energy Impacts for Particulate Control Technology Options**

Control Equipment	Energy Impacts
Fabric Filter (Baghouse)	Moderate electric power requirement for bag shakedown and control system due to pressure drop
Dry Electrostatic Precipitator (ESP)	High electrical power requirement for electrical field creation and control system
Wet Electrostatic Precipitator (WESP)	High electrical power requirement for electrical field creation and control system; also for water circulation and management
Impingement-Plate/Tray Tower Scrubber	Fluid circulation pumps, electrical equipment, and control system
Multiple Cyclones	Particle collection mechanical equipment and control system
Venturi Scrubbers	Fluid circulation pumps, electrical equipment, and control system

**Table 5-6      Summary of Potential Economic Impacts for Particulate Control Technology Options (EPA 2003b)**

<b>Control Equipment</b>	<b>Economic Impact (Cost effectiveness as \$ per US tons per year PM removed)</b>
Fabric Filter (Baghouse)—99.9 % removal efficiency	WTP: \$20,250 to \$131,630 EPA: \$42 to \$266
Dry Electrostatic Precipitator (ESP) 99 % removal efficiency	WTP: \$17,029 to \$136,233 EPA: \$40 to \$250
Wet Electrostatic Precipitator (WESP) 99 % removal efficiency	WTP: \$34,058 to 170,291 EPA: \$55 to \$550
Impingement-Plate/Tray Tower Scrubber 99 % removal efficiency	WTP: \$9,536 to \$241,813 EPA: \$46 to \$1,200
Multiple Cyclones 90 % removal efficiency	WTP: \$4,870 to \$50,202 EPA: \$0.41 to \$420
Venturi Scrubbers 60 % removal efficiency	WTP: \$25,850 to 691,210 EPA: \$76 to \$2,100

**Table 5-7      Summary of the Environmental Impacts of Particulate Matter Control Options**

<b>Control Equipment</b>	<b>Environmental Impact</b>
Fabric Filter (Baghouse or HEPA)	Excellent removal of particulate matter Solid waste, probably hazardous, for disposal
Dry Electrostatic Precipitator (ESP)	Solid waste, probably hazardous, for disposal
Wet Electrostatic Precipitator (WESP)	Solid and liquid waste, probably hazardous, for disposal Possible acid gas, acid mist control
Impingement-Plate/Tray Tower Scrubber	Solid and liquid waste, probably hazardous, for disposal Capture some condensible particulate and acid gases
Multiple Cyclones	Solid waste, probably hazardous, for disposal
Venturi Scrubbers	Solid and liquid waste, probably hazardous, for disposal Capture some condensible particulate and acid gases

**Table 5-8 Diesel-Fired Engines Control Technology**

Supplier	Process	Percent Removal	Technology Feasible Engines >3000 HP	Applied to Stationary Sources
Johnson Matthey – <i>CRT</i>	Passive DPF	85	YES	NO
Nett Technologies	Passive DPF	90	YES	YES
Nett Technologies	DOC	10 to 20	YES	YES
Englehard - <i>DPX</i>	Passive DPF	50 to 80	NO	YES
Cleaire – <i>BUGtrap</i>	Active DPF	85	YES	YES
Donaldson - <i>DCM</i>	DOC	10 to 25	YES	NO
Donaldson - <i>Spiracle</i>	DOC with CCVF	27 to 50	YES	NO
NO <sub>x</sub> TECH	DOC	50 to 90	NO	YES

**Table 5-9 PM Abatement Technologies**

Abatement Technology	Advantages	Disadvantages
Diesel Oxidation Catalyst	Reduces CO and hydrocarbon emissions	Formation of sulfates at high temperatures
Passive Diesel Particulate Filter	High efficiency	Expensive, must use ultra-low sulfur fuel
Active Diesel Particulate Filter	High efficiency, designed for standby engines	Expensive, slight loss in engine power
Diesel Oxidation Catalyst with Crankcase Vent Filtration	Cost-effective, operates effectively with any diesel fuel	Not well developed for stationary sources
NO <sub>x</sub> TECH Emission Control System	Low-sulfur diesel fuel not required	Not efficient for standby equipment



**Table 5-10     Ranking of Technically Feasible Control Technologies by Expected Control Efficiency**

<b>PM Abatement Technology</b>	<b>Maximum PM Control Efficiency (%)</b>	<b>Expected PM Control Efficiency (%)</b>	<b>Generators Annual PM Removal <sup>a</sup> (US tons per year)</b>	<b>Fire Pump Annual PM Removal <sup>b</sup> (US tons per year)</b>	<b>Environmental Impact</b>
Diesel Oxidation Catalyst	25	20	0.20	0.004	Formation of sulfates at high temperature
Diesel Oxidation Catalyst with Crankcase Vent Filtration	50	50	0.50	0.010	Formation of sulfates at high temperature
NO <sub>x</sub> TECH Emission Control System	90	70	0.70	0.014	Ammonia emissions
Passive Diesel Particulate Filter	90	85	0.85	0.017	Disposal of filters
Active Diesel Particulate Filter	90	85	0.85	0.017	Disposal of filters

a    Based on an uncontrolled PM emission rate of 1.0 US ton per year from the standby generators. There are 3 generators each operating 164 hours per year each.

b    Based on an uncontrolled PM emission rate of 0.02 US ton per year from the fire pump. The fire pump operates 100 hours per year.

**Table 5-11 PM Control Options for Standby Diesel Engines**

<b>Control Technique</b>	<b>Description of Technique</b>	<b>PM Reduction Potential (%)</b>	<b>Range of Application</b>	<b>Commercial Availability / Research &amp; Development Status</b>	<b>Comments</b>
Diesel Oxidation Catalyst	Exhaust passes through the converter and causes PM to burn	25	Mobile and stationary sources	Available	
Passive Diesel Particulate Filter	Self-regenerating filter systems oxidize it	90	Mobile and stationary sources	Available	Soot may collect on the filter and not get oxidized due to low exhaust temperatures and short operating times
Active Diesel Particulate Filter	Diesel Particulate Filter with an external heat source for regeneration	90	Standby industrial generators and fire pumps	Available	Designed specifically for standby generators and fire pumps, but not ones as large as 3000 bhp
Diesel Oxidation Catalyst with Crankcase Vent Filtration	DOC with a crankcase vent emissions filtration system	50	Mobile sources	Available but not for large stationary sources	Not yet tested on stationary sources
NOxTECH Emission Control System	Replaces conventional exhaust silencers with a reaction chamber	70	Large industrial engines	Available but not on standby engines	Not efficient in reducing PM on standby engines

**Table 5-12 Ranking of Particulate Control Options for Diesel Generators**

<b>PM Control Technology</b>	<b>Estimated PM Reduction Potential (%)</b>
Diesel Oxidation Catalyst (DOC)	10 to 25
Diesel Particulate Filter (DPF)	80 to 90

**Table 5-13 Results of BACT Evaluation for Control of Radionuclide and All Particulates**

Facility	Emission Unit	Stream Number	Description	Proposed BACT
Pretreatment Facility	PT-S3	S41z	Process vessel vent	HEPA
		SVS137	Process vessel vent from former LAW pretreatment plant	
		S_9v/S17	Evaporator offgas from LAW feed evaporator	
		S74/S1	Evaporator offgas from LAW feed evaporator from former LAW pretreatment plant	
	PT-S4	S41	RFD/PJM exhaust	HEPA
		VS18	RFD/PJM exhaust from former LAW pretreatment plant	
	PT S2	N/A	Pretreatment building vent system	HEPA
LAW	LV-S3	S_85	LAW melter offgas	HEPA
		S52	Process vessel vent	
	LV-S2	N/A	LAW building vent system	HEPA
HLW	HV-S3	S_120	HLW melter offgas	HEPA
		S_127	Process vessel vent	
	HV-S4	S105J	RFD/PJM exhaust	HEPA
	HV-S2	N/A	HLW building vent system	HEPA
Laboratory	LB-C2, LB-S1, LB-S2	N/A	Laboratory building ventilation system	HEPA

**Table 5-13 Results of BACT Evaluation for Control of Radionuclide and All Particulates**

<b>Facility</b>	<b>Emission Unit</b>	<b>Stream Number</b>	<b>Description</b>	<b>Proposed BACT</b>
BOF	Boilers	N/A	Industrial boilers operated to provide high pressure steam for the WTP	Good combustion engineering practices Particulate emission limit of 0.020 lb/mmBtu
BOF	Diesel -Fired Generators and Fire Water Pumps	N/A	Diesel generators used to provide electrical power in the event of the loss of site power and operate fire water pumps	Good combustion engineering practices Limited testing hours
BOF	Glass former facility	N/A	Storage facility designed to receive, store, weigh, blend, and transport glass former materials	Baghouse

## Contents

<b>6</b>	<b>Air Quality Impact Analysis.....</b>	<b>6-1</b>
6.1	Ambient Air Standards.....	6-1
6.2	Emission Sources.....	6-2
6.2.1	Release Characteristics .....	6-2
6.2.2	Modeled Emission Rates.....	6-2
6.3	Building Downwash .....	6-3
6.4	Modeling Source Groups.....	6-3
6.5	Meteorological Data .....	6-3
6.6	Modeled Receptors.....	6-3
6.7	Modeling Analysis .....	6-4
6.7.1	Near-Field Impacts.....	6-4
6.7.2	Far-Field Impacts .....	6-5
6.8	Additional Impacts Analysis .....	6-5
6.8.1	Growth and Construction .....	6-5
6.8.2	Ambient Air Quality Impact .....	6-5
6.8.3	Soils and Vegetation Analysis .....	6-5
6.8.4	Visibility Impairment Analysis.....	6-6

## Tables

Table 6-1	WTP Source Release Parameters used for PSD Modeling.....	6-7
Table 6-2	NO <sub>x</sub> Emission Estimates and Modeled Emission Rates by WTP Process .....	6-7
Table 6-3	PM <sub>10</sub> Emission Estimates and Modeled Emission Rates by WTP Process.....	6-8
Table 6-4	Identification and Distance to Class I Areas Surrounding the WTP.....	6-8
Table 6-5	Summary of Maximum Modeled Impacts and Significance Determinations .....	6-9
Table 6-6	Summary of Annual Average NO <sub>x</sub> Concentrations at Class I Wilderness Areas Surrounding the WTP.....	6-9

## Figures

Figure 6-1	Map of Hanford Site Showing 1.0 µg/m <sup>3</sup> Concentration Isopleth for Annual Average NO <sub>2</sub> Impacts.....	6-10
Figure 6-2	Map of Hanford Site Showing 1.0 µg/m <sup>3</sup> Concentration Isopleth for Annual Average PM <sub>10</sub> Impacts .....	6-11

## 6 Air Quality Impact Analysis

The emissions inventory shows that project emissions will exceed PSD significant levels for  $\text{NO}_x$  and for  $\text{PM}_{10}$ . The PSD significance level is 40 US tons per year for  $\text{NO}_x$  and 15 US tons per year for  $\text{PM}_{10}$ . Therefore, an air quality impact analysis is required for these 2 criteria pollutants.

The primary regulatory concern for new sources or major modifications of existing sources located in an attainment area is that proposed project emissions would not cause or contribute to a violation of any NAAQS, or cause an exceedance of a Class I increment at a wilderness area or national park. For this analysis, emissions data from the WTP and onsite meteorological data have been used in the *Industrial Source Complex - Short Term* (ISCST3) air dispersion model, version 02035, to determine compliance with these requirements. The ISCST3 was used to determine the maximum annual and 24-hour average ground-level air concentrations attributable to the WTP.

Air concentrations resulting from the WTP emissions were calculated by the ISCST3 model at receptors grouped into 3 areas: along the Hanford property boundary, along the Columbia River (which is inside the property boundary along the eastern edge), and at several onsite receptors that have public access. The ISCST3 model output is provided in Appendix D of this application.

### 6.1 Ambient Air Standards

For the purpose of determining compliance with ambient standards, all  $\text{NO}_x$  emissions were modeled as  $\text{NO}_2$  for which there is an NAAQS. Similarly, it was assumed that all emissions of particulate matter are emitted as  $\text{PM}_{10}$ . The standards and criteria for determining project compliance with PSD requirements are described below.

- The NAAQS have been established to set a nationwide limit for each criteria pollutant. There is 1 ambient air standard for  $\text{NO}_2$ , which is a  $100 \mu\text{g}/\text{m}^3$  annual average. For  $\text{PM}_{10}$  there are 2 ambient standards: a  $150 \mu\text{g}/\text{m}^3$  24-hour average and a  $50 \mu\text{g}/\text{m}^3$  annual average. The total impact from the proposed facility and background  $\text{NO}_2$  and  $\text{PM}_{10}$  levels must not exceed these NAAQS limits.
- A simplification of the air quality impact analysis can occur if initial modeling demonstrates that the annual average concentration of  $\text{NO}_2$  and  $\text{PM}_{10}$  from the proposed project is less than the significant ambient impact level of  $1 \mu\text{g}/\text{m}^3$ , at any location outside the property fence line or at other locations where there is public access. For  $\text{PM}_{10}$ , there is a second significance level of  $5 \mu\text{g}/\text{m}^3$  for 24-hour average concentrations. If these criteria are met, then the proposed project is assumed to have no significant impact and the analysis is completed.
- If the predicted ambient air impact of  $\text{NO}_2$  or  $\text{PM}_{10}$  from a project is found to exceed the significant impact level of  $1 \mu\text{g}/\text{m}^3$ , the project may not consume more than the allowable PSD increment of  $25 \mu\text{g}/\text{m}^3$ . This is determined with a full impact analysis, which must include the impacts from other PSD sources in the area in addition to the impact from the proposed new or modified facility.
- Independent of these standards, which are applied to public access areas in the vicinity of the proposed facility, there is a more stringent PSD increment that applies to Class I areas managed by the US Forest Service, National Park Service, and the US Fish and Wildlife Service. In these areas, which may be located at extended distances from the proposed facility, there is a Class I PSD increment of  $1 \mu\text{g}/\text{m}^3$  for  $\text{NO}_2$  and  $\text{PM}_{10}$  that may not be exceeded.

## **6.2 Emission Sources**

Potential emission sources of NO<sub>x</sub> and PM<sub>10</sub> include an offgas emission unit for each of the 3 WTP process plants (pretreatment, LAW vitrification, and HLW vitrification plants), a stack for boiler emissions, and a stack for internal combustion equipment. Building ventilation and laboratory stacks will not emit NO<sub>x</sub> or PM<sub>10</sub>, and therefore were not considered in the modeling analysis. The boiler equipment will include 3 boilers that will run year-round (or 8760 hours per year), and 3 boilers that will operate approximately 42 % of the year (or 3679 hours per year). Internal combustion equipment includes 3 generators and 2 fire water pumps. Because of similarities in their release characteristics, emissions from the boilers were combined and modeled as a single emission source. Similarly, emissions from the generators and the fire water pumps were combined and modeled as a single emission source.

### **6.2.1 Release Characteristics**

Stack emissions for process equipment, boilers, and internal combustion sources were modeled as point sources with release parameters corresponding to design specifications. Release parameters such as the stack diameter and exhaust gas temperature for the pretreatment, LAW vitrification, and HLW vitrification flues are based on site-specific engineering designs developed for the WTP. Release parameters for boiler and internal combustion engines associated with steam and heat production, and emergency power, were developed using manufacturers' data based on WTP equipment size and function. A summary of the release parameters for the modeled sources is shown in Table 6-1.

Fugitive emissions are those "which could not reasonably pass through a stack, chimney, vent or other functionally equivalent opening" (40 CFR 52.21(b)(20)). Since the WTP does not fall into 1 of the 28 named PSD source categories with 100 US tons per year major source threshold levels, fugitive emissions do not have to be included in the potential to emit summary to determine the significance of pollutant emissions. Moreover, the only fugitive emissions expected from the WTP are associated with vehicle traffic such as road dust and tailpipe emissions. While these fugitive emissions do not have to be included in the emission inventory and the preliminary air quality analysis, they may have to be quantified if a full impact air quality modeling analysis were to be required. Secondary emissions of NO<sub>x</sub> (from the temporary increase in vehicular tailpipe exhaust gases associated with growth and construction as the result of the project) are expected to be insignificant, but will be discussed in the additional impacts analysis.

### **6.2.2 Modeled Emission Rates**

Actual annual emission estimates for all emission sources, reported as US tons per year, were annualized over a continuous operating schedule of 8760 hours per year to allow the model to predict annual concentrations using a full year of onsite meteorological data. Table 6-2 and Table 6-3 show actual emission estimates (US tons per year) and annualized average emission rates (pounds per hour), as modeled, for sources of NO<sub>x</sub> and PM<sub>10</sub>, respectively. Detailed presentation of emission rates of NO<sub>x</sub> and PM<sub>10</sub> from point sources at the WTP is provided in section 3 of this application.

Maximum daily emission rates had to be calculated for comparison with the 24-hour NAAQS of PM<sub>10</sub>. Because the process flues for pretreatment, LAW vitrification, and HLW vitrification will operate 8760 hours per year, the maximum daily emission rate is the same as the average daily emission rate. Therefore, emission rates for these releases did not change for the PM<sub>10</sub> 24-hour analysis. Maximum daily emissions were calculated separately for the boilers and internal combustion equipment. Daily emissions for the boilers were calculated assuming that all 6 boilers operate continuously for a 24-hour

period. Daily emissions for the generators and the fire water pumps were calculated by using the maximum hours of operation the equipment would be operated within a single 24-hour period. In the case of the generators, the testing will not exceed 8 hours in a 24-hour period to simulate the event of loss of power. For the fire water pumps, the maximum test will be 3 hours in a 24-hour period for annual testing. Table 6-3 summarizes maximum 24-hour PM<sub>10</sub> emissions rates.

### **6.3 Building Downwash**

The building profile input program (BPIP) has been run to determine dominant structures for building downwash calculations made in ISCST3 for point sources. Direction-specific building heights and widths of the dominant downwash structures have been included in the ISCST3 model data input file directly from the BPIP results.

### **6.4 Modeling Source Groups**

The ISCST3 model allows users to group contributions from all sources together for comparison to an NAAQS. Potential emission sources at the WTP as discussed in section 3 of this application were modeled as a single source group in the ISCST3 model to determine impacts based on combined emissions. Thus, the model calculates a total impact at a specified receptor by summing the individual impacts contributed by each source for each averaging period included in the modeling analysis. Sources included in the modeling analysis for NO<sub>x</sub> and PM<sub>10</sub> are identified in Table 6-2 and Table 6-3, respectively.

### **6.5 Meteorological Data**

The ISCST3 model has been run with a sequential hourly meteorological data set for a 5-year period, from 1994 through 1998. Surface air data such as wind direction, wind speed, temperature, and precipitation have been obtained from Station 6 of the Hanford Meteorological Monitoring Network, which is located in the 200 East Area within 1 mile of the location of the WTP. Upper air data used to calculate mixing heights has been obtained from the National Weather Service (NWS) station in Spokane, Washington, which is located approximately 150 miles northeast of Hanford, and is the most representative upper air NWS station east of the Cascade Mountains.

### **6.6 Modeled Receptors**

The modeling analysis included discrete receptors used to identify the maximum impact, impacts to Class I Areas, and a regularly spaced grid used for contouring concentration isopleths for NO<sub>x</sub> and PM<sub>10</sub>. To determine impacts at the nearest Class I Areas, the ISCST3 model was used to calculate NO<sub>2</sub> and PM<sub>10</sub> concentrations at a point within the Class I Area closest to the WTP. A list of the Class I wilderness areas and their distance to the WTP is presented in Table 6-4.

For predicting maximum impacts at an offsite or public access receptor, a receptor grid with 250-meter spacing was placed around the entire fence line of the Hanford Site and along the portion of the Columbia River that flows through the site. Because preliminary modeling runs showed prevailing winds to the east, a receptor grid with 500-meter spacing was extended 10 kilometers around the eastern property boundary to be sure that the maximum impacts were identified. In addition, 4 onsite public access locations were considered. These included the following locations: 1) Laser Interferometer Gravitational Wave Observatory (LIGO) facility, 2) Energy Northwest, 3) Richland Specialty Extrusions, and 4) 300 Area Washington State University Laboratory. A total of over 2700 receptors have been modeled to



determine the highest ground-level concentration at an offsite receptor (that is, fence line or beyond) or public access location.

The state plane coordinate system has been used to locate all modeled emissions sources, receptors and buildings. Complex terrain modeling has been performed using elevation data obtained from topographic information contained in the digitized Hanford geographical information system (GIS) grid. Elevations have been determined for all sources, receptors, and buildings, and used in the ISCST3 modeling.

## **6.7 Modeling Analysis**

The ISCST3 model incorporates complex terrain algorithms that have been enabled to predict ground-level concentrations at receptors above source plume heights (effective stack-height) or between stack and plume heights. The ISCST3 model was used in the rural mode with model option switches set to regulatory-default settings. Output from the ISCST3 model output is provided in Appendix D of this application.

The modeling has been conducted in 2 areas: near-field impacts around the Hanford boundary, and far-field impacts at the nearest Class I areas.

### **6.7.1 Near-Field Impacts**

#### **Annual Average Impacts**

The maximum annual average  $\text{NO}_2$  and  $\text{PM}_{10}$  concentrations from the WTP project were calculated using the ISCST3 model. The highest annual average impact at an offsite receptor or public access point was calculated to be  $0.61 \mu\text{g}/\text{m}^3$  for  $\text{NO}_2$  and  $0.11 \mu\text{g}/\text{m}^3$  for  $\text{PM}_{10}$ , based on the Hanford meteorological data set for the worst-case year (1997). These results are presented in Table 6-5. The location of the maximum concentrations is the elevated terrain to the east of the WTP facility, across the Columbia River in the Ringold and White Bluffs area.

The area within the  $1 \mu\text{g}/\text{m}^3$  concentration isopleth for predicted  $\text{NO}_2$  and  $\text{PM}_{10}$  impacts from the proposed project are shown in Figure 6-1 and Figure 6-2, respectively. Because the results of the modeling analyses show that the maximum average annual  $\text{NO}_2$  and  $\text{PM}_{10}$  concentrations at an offsite receptor or public access point are below the  $1.0 \mu\text{g}/\text{m}^3$  threshold level, there will be no significant impact from the proposed source.

#### **Maximum 24-Hour Average Impacts**

The maximum 24-hour average  $\text{PM}_{10}$  concentrations were calculated using the ISCST3 model. The highest 24-hour impact at an offsite receptor or public access point was calculated to be  $1.93 \mu\text{g}/\text{m}^3$  for  $\text{PM}_{10}$ , based on the Hanford meteorological data set for the worst-case year (1997). These results are presented in Table 6-5.

Because the results of the modeling analyses show that the maximum 24-hour average  $\text{PM}_{10}$  concentrations at an offsite receptor or public access point is below the  $5.0 \mu\text{g}/\text{m}^3$  threshold level, there will be no significant impact from the proposed source.

### 6.7.2 Far-Field Impacts

The nearest Class I Areas are located at extended distances from the WTP, as shown in Table 6-6: Alpine Lakes Wilderness Area (137 km to the northwest); Goat Rocks Wilderness Area (142 km to the west); Mt. Adams Wilderness Area (153 km to the west-southwest); Mt. Rainier National Park (153 km to the west-northwest); and the Eagle Cap Wilderness Area (185 km to the southeast). Because there have been no modeled concentrations above  $1.0 \mu\text{g}/\text{m}^3$  on the Hanford site, the impacts from the WTP at these Class I Areas are well below the Class I Area increment standard of  $1.0 \mu\text{g}/\text{m}^3$ . The Class I Area with the highest average annual concentration for  $\text{NO}_x$  and  $\text{PM}_{10}$  emissions is the Eagle Cap Wilderness Area. The predicted impact for  $\text{NO}_x$  is  $0.00505 \mu\text{g}/\text{m}^3$ , and the predicted impact for  $\text{PM}_{10}$  is  $0.00080 \mu\text{g}/\text{m}^3$  on an annual average and  $0.058 \mu\text{g}/\text{m}^3$  on a 24-hour average (see Table 6-6). The highest impacts are predicted to be at the Eagle Cap Wilderness Area because the dominant west-northwest and northwest winds preferentially transport the emissions to the southeast, in the direction of that wilderness area.

## 6.8 Additional Impacts Analysis

The additional impact analysis has 4 parts: 1) growth and construction, 2) ambient air quality impact, 3) soils and vegetation impacts, and 4) visibility impairment.

### 6.8.1 Growth and Construction

An analysis has been made to develop a general plan for the transportation requirements of the WTP. That report, 24590-WTP-ENG-01-007, *River Protection Project - Waste Treatment Plant Site Transportation Report*, identifies traffic patterns and volume associated with the project and concludes that the plant site road system developed for the project is adequate. Supplemental information will be developed as the design proceeds. Air quality impacts will be confined to the Hanford Site itself, except for the possible increase of vehicular traffic during construction and operation of the proposed facility.

### 6.8.2 Ambient Air Quality Impact

The WTP is a PSD source for  $\text{NO}_x$  and  $\text{PM}_{10}$  emissions. Other criteria pollutants will be emitted at rates that are not considered significant under PSD regulations. Air quality modeling has shown that the annual average maximum offsite impact of  $\text{NO}_2$  at the Hanford Site is less than  $1 \mu\text{g}/\text{m}^3$ , the Class I PSD increment for  $\text{NO}_2$  and  $\text{PM}_{10}$ . The Class I increment thresholds are set at very low levels to help protect sensitive characteristics, such as flora, fauna, soils, and lakes, of national parks and wilderness areas. For other criteria pollutants that are released at insignificant emission rates, the offsite air quality impacts are expected to be negligible.

### 6.8.3 Soils and Vegetation Analysis

As noted, the annual average maximum offsite impact of  $\text{NO}_2$  at the Hanford Site is less than  $1 \mu\text{g}/\text{m}^3$ . In general, the semi-arid climate in the vicinity of the WTP has resulted in soils and vegetation that are not very sensitive to low levels of  $\text{NO}_x$  emissions. Therefore, it is not expected that the very low emissions from the WTP will have any impact on the soils and vegetation in the vicinity of the facility. For other criteria pollutants that are released at insignificant emission rates, the offsite air quality impacts on soils and vegetation are expected to be negligible.

#### 6.8.4 Visibility Impairment Analysis

The federal CAA gives federal land managers (FLMs) an affirmative responsibility to protect the natural resources of Class I Areas from adverse impacts of air pollution. FLM responsibilities include the review of air quality applications from proposed new or modified major pollution sources near these Class I Areas.

One of the most sensitive air quality related values in Class I Areas is visibility. The FLMs have visibility protection responsibility under 40 CFR 51.307, *New Source Review*, and 40 CFR 52.27, *Protection of Visibility from Sources in Attainment Areas*. The latest guidance for the determination of visibility impacts is provided in a recent document, *Federal Land Managers' Air Quality Related Work Group (FLAG), Phase 1 Report* (US Forest Service 2000).

The FLAG report states: "Generally, the permitting authority should notify the FLM of all new or modified major facilities proposing to located within 100 km (62 miles) of a Class I area. In addition, the permitting authority should notify the FLM of 'very large sources' with the potential to affect Class I areas proposing to locate at distances greater than 100 km." The WTP is located at a distance of 137 km from the nearest Class I Area, and 185 km from the Class I Area (Eagle Cap Wilderness Area) that is in the downwind direction of the prevailing winds. In addition, the WTP is predicted to have maximum annual NO<sub>x</sub> emissions of approximately 159 US tons per year, which does not constitute a very large source (as defined above). Therefore, because of the relatively low NO<sub>x</sub> emissions rate and the extended distance to the nearest Class I Areas, it is expected that the facility will not impact visibility at these Class I Areas.

**Table 6-1 WTP Source Release Parameters used for PSD Modeling**

Stack Parameter	Pretreatment	LAW	HLW	Steam Boiler Plant <sup>a</sup>	Backup Generators and Fire Water Pumps
Stack height (ft)	200	200	200	35	8.35
Stack temperature (°F)	116	170	135	350	953
Exit diameter (ft)	1	2	1	1	1
Exit velocity (ft/s)	58.04	31.79	32.22	63.66	0.001 <sup>c</sup>
Exit flow rate (acfm) <sup>b</sup>	2735	5992	1518	3000	0.155 <sup>c</sup>

a The steam boiler plant stack parameters are estimates for PSD modeling purposes.

b Actual cubic feet per minute

c A nominal exit velocity of 0.001 meter per second (m/s) is applied to horizontal releases.

**Table 6-2 NO<sub>x</sub> Emission Estimates and Modeled Emission Rates by WTP Process**

Process	Annual Emission Estimates (US tons per year)	Annualized Average Emission Rate, as Modeled (pounds per hour)
LAW Offgas	36.7	8.38
HLW Offgas	8.50	1.94
Steam Plant	84.3	19.25
Generators and fire water pump <sup>a</sup>	29.8	6.79
<b>Total</b>	<b>159.3</b>	<b>36.31</b>

Notes:

1 ton = 2000 pounds

a Emissions include diesel generators and diesel-fired fire water pumps (29.39 US tons, and 0.37 US tons, respectively).

**24590-WTP-RPT-ENV-01-007, Rev 1**  
**Prevention of Significant Deterioration Application for**  
**Hanford Tank Waste Treatment and Immobilization Plant**

**Table 6-3 PM<sub>10</sub> Emission Estimates and Modeled Emission Rates by WTP Process**

<b>Process</b>	<b>Annual Emission Estimates (US tons per year)</b>	<b>Annualized Average Emission Rate, As Modeled (pounds per hour)</b>	<b>24-hour Average Emission Rate, As Modeled (pounds per hour)</b>
Pretreatment Offgas	2.04	0.465	0.465
LAW Offgas	1.58	0.360	0.360
HLW Offgas	1.18	0.269	0.269
Steam Plant	18.7	4.269	6.025
Generators and fire water pump <sup>a</sup>	1.0	0.228	3.995
<b>Total</b>	<b>24.56</b>	<b>5.591</b>	<b>11.114</b>

Notes:

1 ton = 2000 lb.

a Emissions include diesel generators and diesel-fired fire water pump (3.89 US tons, and 0.24 US tons, respectively).

**Table 6-4 Identification and Distance to Class I Areas Surrounding the WTP**

<b>Class I Area</b>	<b>Approximate Distance from WTP km (mi)</b>	<b>Direction</b>
Alpine Lakes Wilderness Area	137 km (85 mi)	North West
Goat Rocks Wilderness Area	142 km (88 mi)	West
Mt Adams Wilderness Area	153 km (95 mi)	West South West
Mt. Rainier National Park	153 km (95 mi)	West North West
Eagle Cap Wilderness Area	185 km (115 mi)	South East

km: kilometer  
mi: mile

**24590-WTP-RPT-ENV-01-007, Rev 1**  
**Prevention of Significant Deterioration Application for**  
**Hanford Tank Waste Treatment and Immobilization Plant**

**Table 6-5 Summary of Maximum Modeled Impacts and Significance Determinations**

<b>National Ambient Air</b>	<b>NO<sub>x</sub> Annual Average Concentration (µg/m<sup>3</sup>)</b>	<b>PM<sub>10</sub> Annual Average Concentration (µg/m<sup>3</sup>)</b>	<b>PM<sub>10</sub> 24-Hour Average Concentration (µg/m<sup>3</sup>)</b>
Maximum predicted concentration from proposed project	0.61	0.11	1.93
Significance threshold	1.0	1.0	5.0
Significance determination	No	No	No

**Table 6-6 Summary of Annual Average NO<sub>x</sub> Concentrations at Class I Wilderness Areas Surrounding the WTP**

<b>Class I Area</b>	<b>NO<sub>x</sub> Annual Average Concentration (µg/m<sup>3</sup>)</b>	<b>PM<sub>10</sub> Annual Average Concentration (µg/m<sup>3</sup>)</b>	<b>PM<sub>10</sub> 24-Hour Average Concentration (µg/m<sup>3</sup>)</b>
Alpine Lakes Wilderness Area	0.00250	0.00041	0.049
Goat Rocks Wilderness Area	0.00194	0.00030	0.053
Mt Adams Wilderness Area	0.00175	0.00027	0.046
Mt. Rainier National Park	0.00316	0.00047	0.046
Eagle Cap Wilderness Area	0.00505	0.00080	0.058

Figure 6-1 Map of Hanford Site Showing  $1.0 \mu\text{g}/\text{m}^3$  Concentration Isopleth for Annual Average  $\text{NO}_2$  Impacts

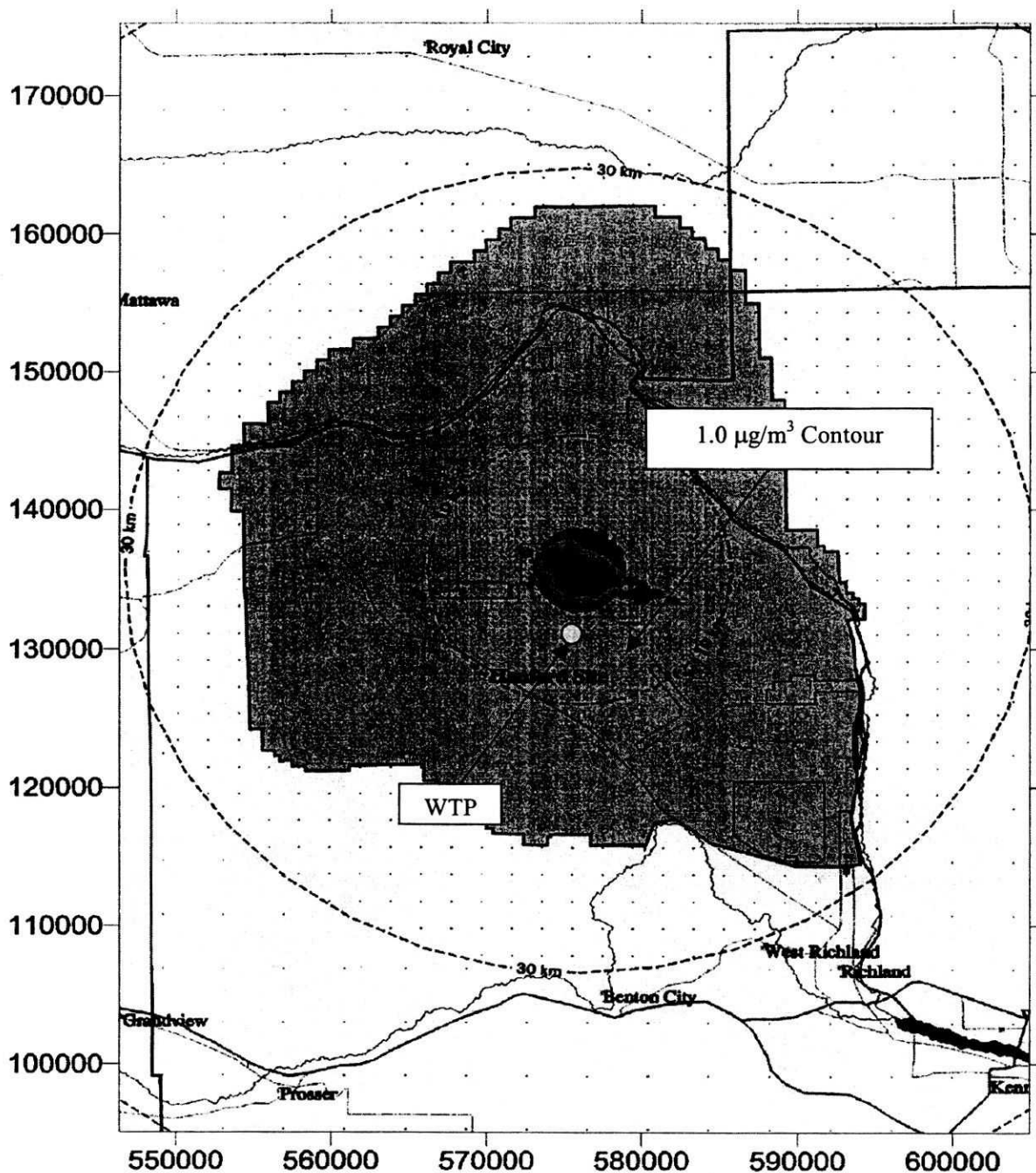
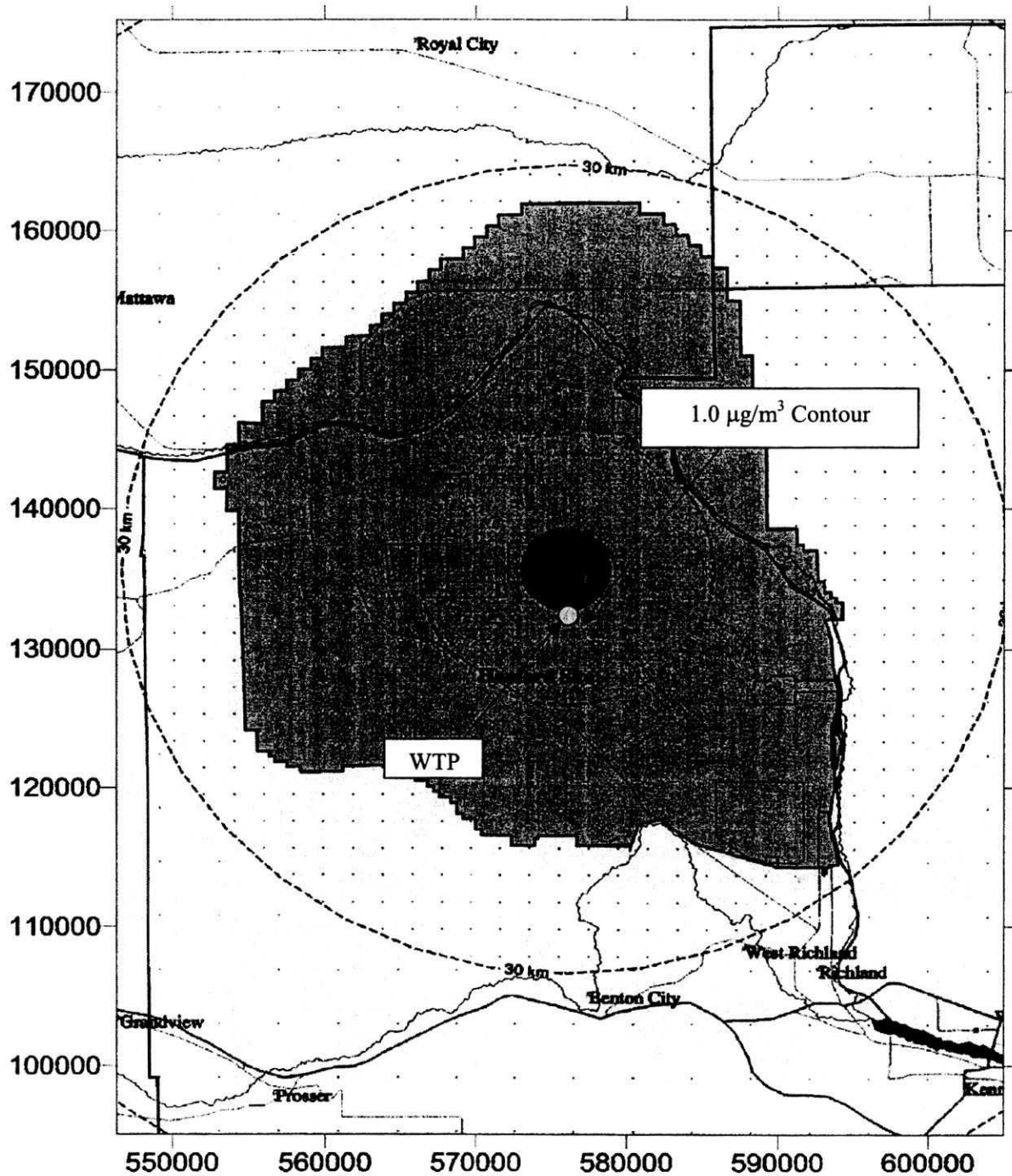


Figure 6-2 Map of Hanford Site Showing  $1.0 \mu\text{g}/\text{m}^3$  Concentration Isopleth for Annual Average  $\text{PM}_{10}$  Impacts





## Contents

---

7	References.....	7-1
7.1	Project Documents .....	7-1
7.2	Codes and Standards .....	7-1
7.3	Other Documents .....	7-2

## 7 References

### 7.1 Project Documents

24590-BOF-3YD-HPS-00001, *System Description of High Pressure Steam (HPS) and Steam Condensate Water Systems (SCW)*.

24590-PTF-MKC-PVP-00001, *Radiolytic NO<sub>x</sub> Evolution in PT High Activity Process Vessels*.

24590-WTP-ENG-01-007, *River Protection Project – Waste Treatment Plant Site Transportation Report*.

24590-WTP-MRQ-PO-03-002, *Emissions Maximum Case Runs with Updated Parameters*.

24590-WTP-RPT-ENV-01-004, *Best Available Radionuclide Control Technology Analysis for the WTP*.

24590-WTP-RPT-ENV-01-008, *Radionuclide Air Emissions Notice of Construction Permit Application for the River Protection Project - Waste Treatment Plant*.

24590-WTP-M3C-HOP-00001, *Melter Offgas and Liquid Effluent Definition*.

RPT-W375HV-PR00001, *HLW Vitrification Process Offgas System Evaluation*.

RPT-W375LV-TE00008, *Evaluation of Alternatives for the LAW Melter Offgas System*.

### 7.2 Codes and Standards

40 CFR 51.166. *Requirements for Preparation, Adoption, and Submittal of Implementation Plans*. Code of Federal Regulations, as amended.

40 CFR 51.307. *New Source Review*. Code of Federal Regulations, as amended.

40 CFR 52.21. *Prevention of Significant Deterioration of Air Quality*. Code of Federal Regulations, as amended.

40 CFR 52.27. *Protection of Visibility from Sources in Attainment Areas*. Code of Federal Regulations, as amended.

40 CFR 52.2497. *Significant Deterioration of Air Quality*. Code of Federal Regulations, as amended.

40 CFR Part 63 Subpart EEE. *National Emission Standards for Hazardous Air Pollutants from Hazardous Waste Combustors*, as amended.

40 CFR 60.42. *Standards of Performance for New Stationary Sources: Standard for particulate matter*, as amended.

40 CFR 60.44. *Standards of Performance for New Stationary Sources: Standard for nitrogen oxides*, as amended.

40 CFR 60, Appendix B. *Standards of Performance for New Stationary Sources: Performance Specifications*, as amended.

40 CFR 68. *Chemical Accident Prevention Provisions*. Code of Federal Regulations, as amended.

ASME. 1997. *Code on Nuclear Air and Gas Treatment*, Addenda A ASME -AG-1. Committee on Nuclear Air and Gas Treatment (CONAGT).

CAA. 1970. *Clean Air Act of 1970*, 42 United States Code, Section 7401. US Congress, Washington, DC, USA, as amended.

Ecology, EPA and DOE. 1998. *Hanford Federal Facility Agreement and Consent Order*, as amended through December 31, 1998. Washington State Department of Ecology, Olympia, Washington, USA; US Environmental Protection Agency, Washington, DC, USA; US Department of Energy, Washington, DC, USA.

FR 41838. 1996. *Prevention of Significant Deterioration*, Federal Register, Volume 61, 41838, 12 August 1996.

WAC 173-400. *General Regulations for Air Pollution Sources*. Washington Administrative Code, as amended.

WAC 173-401. *Operating Permit Regulation*. Washington Administrative Code, as amended.

WAC 173-460. *Controls for New Sources of Toxic Air Pollutants*. Washington Administrative Code, as amended.

### **7.3 Other Documents**

Alley. 1998. *Control of Nitrogen Oxide Emissions*, Chapter 25, Roberts & Associates, Inc., Air Quality Control Handbook, p 25.1-25.21. McGraw-Hill, New York, New York, USA.

Baide. 1992. *An Evaluation of Potentially Applicable Control Technologies for Nitrogen Oxide Emissions from the Hanford Waste Vitrification Project*, WHC-MR-0393. Westinghouse Hanford Company, Richland, Washington, USA.

Buonicore Davis. 1992. *Air Pollution Engineering Manual*, Air and Waste Management Association (AWMA). Van Nostrand Reinhold, New York.

Calcagni. 1989. Memorandum from Calcagni J, Director of Air Quality Management Division, Office of Air Quality Planning and Standards, US Environmental Protection Agency, to Director, Air Management Divisions, Regions I, III, and IX and others, *Transmittal of Background Statement on Top-Down Best Available Control Technology (BACT)*, 13 June 1989.

Chen. 1990. *Deactivation of the Vanadia Catalyst in the Selective Catalytic Reduction Process*. Journal of Air and Waste Management Association, Volume 40, p 1403-1409.

Chen and Yang. 1990. *Mechanism of Poisoning of the  $V_2O_5/TiO_2$  Catalyst for the Reduction of  $NO_x$  by  $NH_3$* . Journal of Catalysis, Volume 125, p 411-420.

- Cleaire. 2003. Personal Communication Tom Thomas. (510) 347-6632. San Leandro, California, USA.
- Cooper and Alley. 1994. *Air Pollution Control-A Design Approach*, Second Edition. Cooper C and Alley F, Waveland Press, Inc.
- Donaldson. 2003. Personal Communication with Pamra. Donaldson Company, Inc., (952) 887-3556. Minneapolis, Minnesota, USA.
- Ecology. 2002. The Hanford Facility Resource Conservation And Recovery Act Draft Permit for the Treatment, Storage, And Disposal Of Dangerous Waste, Publication Number 01-05-006, May 2002.
- Englehard. 2003. Personal Communication with Al Bouney. Englehard Corporation, (732) 205-6146. Iselin, New Jersey, USA.
- EPA. 1979. *NO<sub>x</sub> Abatement for Stationary Sources in Japan*, Ando, Jumpei, August 1979. US Environmental Protection Agency, Washington, DC, USA.
- EPA. 1990a. *New Source Review Workshop Manual-Prevention of Significant Deterioration and Nonattainment Area Permitting*, Draft, October 1990. US Environmental Protection Agency, Washington, DC, USA.
- EPA. 1990b. "Top-Down" Best Available Control Technology Guidance Document, draft, 15 March 1990. US Environmental Protection Agency, Washington, DC, USA.
- EPA. 1991. *Radiation and Mixed Waste Incineration, Background Information Document, Volume 1: Technology*. EPA 520/1-91-010. Research Triangle Park, North Carolina, USA.
- EPA. 1993. AP-42. *Compilation of Air Pollution Emission Factors*, Fifth Edition, Volume I, Chapter 8: Inorganic Chemical Industry, Section 8.12, Sodium Carbonate. Office of Air Quality Planning and Standards. US Environmental Protection Agency, Washington, DC, USA.
- EPA. 1996. AP-42. *Compilation of Air Pollution Emission Factors*, Fifth Edition, Volume I, Chapter 3: Stationary Internal Combustion Sources, Section 3.4, Large Stationary Diesel and All Stationary Dual-Fuel Engines. Office of Air Quality Planning and Standards. US Environmental Protection Agency, Washington, DC, USA.
- EPA. 1998a. *National Air Quality Trends*. US Environmental Protection Agency, Washington, DC, USA.
- EPA. 1998b. AP-42. *Compilation of Air Pollution Emission Factors*, Forth Edition, Volume I, Chapter 1: External: Combustion Sources, Section 1.3, Fuel Oil Combustion. Office of Air Quality Planning and Standards. US Environmental Protection Agency, Washington, DC, USA.
- EPA. 1998c. AP-42. *Compilation of Air Pollution Emission Factors*, Fifth Edition, Volume I, Chapter 1: External: Combustion Sources, Section 1.3, Fuel Oil Combustion. Office of Air Quality Planning and Standards. US Environmental Protection Agency, Washington, DC, USA.
- EPA. 1998d. *Stationary Source Control Techniques Document for Fine Particulate Matter*, EPA-452/R-97-001. US Environmental Protection Agency, Washington, DC, USA.

- EPA. 1999a. "Cyclones". *EPA-CICA Pollution Technology Fact Sheet*. <http://www.epa.gov/ttn/catc/>.
- EPA. 1999b. "Dry Electrostatic Precipitator, Wire-Plate Type". *EPA-CICA Pollution Technology Fact Sheet*. Technology Transfer Network, Clean Air Technology Center. <http://www.epa.gov/ttn/catc/>.
- EPA. 1999c. "Wet Electrostatic Precipitator, Wire-Plate Type". *EPA-CICA Pollution Technology Fact Sheet*. Technology Transfer Network, Clean Air Technology Center. <http://www.epa.gov/ttn/catc/>.
- EPA. 1999d. "Venturi Scrubber". *EPA-CICA Pollution Technology Fact Sheet*. Technology Transfer Network, Clean Air Technology Center. <http://www.epa.gov/ttn/catc/>.
- EPA. 2000. "Fabric Filter HEPA and ULPA Type". *EPA-CICA Pollution Technology Fact Sheet*. Technology Transfer Network, Clean Air Technology Center. <http://www.epa.gov/ttn/catc/>.
- EPA. 2003a. Technology Transfer Network, Clean Air Technology Center, RACT/BACT/LAER Clearinghouse, RBLC Query Results, Particulate Matter, fuel-oil fired boilers, March 20, 2003.
- EPA. 2003b. "Diesel Particulate Matter (PM) Filter Overview". Transportation and Air Quality. [http://www.epa.gov/otaq/retrofit/documents/bigdig\\_case\\_08.htm](http://www.epa.gov/otaq/retrofit/documents/bigdig_case_08.htm).
- Farrauto. 1999. Engelhard Corporation, Personal Communication with Olson B, SAIC, 28 October 1999.
- Fluor Daniel. 1991. *A Conceptual Study of Metal Fiber Filters for Nuclear Air Cleaning in the HWVP*. Fluor Technology, Inc., Advanced Technology Division, Irvine, California, USA.
- Goles. 1987. *NO<sub>x</sub> Emissions Abatement Technologies*, HWVP-87-V110305B, September 1987. Pacific Northwest Laboratory, Richland, Washington, USA.
- ICAC. 1997. Institute of Clean Air Companies, Inc., Selective Catalytic Reduction (SCR) Controls to Abate NO<sub>x</sub> Emissions, White Paper, October 1994 and November 1997.
- ICAC. 2003. Institute of Clean Air Companies, Control Technology Descriptions, Particulate Controls, 1660 L Street, Suite 1100, Washington, DC, March 2003.
- Johnson. 2003. Personal Communication Rich Rosowski. Johnson Matthey, Plc, (610) 341-3445. Malvern, Pennsylvania, USA.
- McIntyre. 1994. Personal Communication between McIntyre A., Technical Sales Engineer for Exxon Research and Engineering, Menlo Park, California, USA, and Potter D, SAIC, Emmorton, Maryland, USA, July 1994.
- Niepow. 2003. Letter: Boilers for Hanford Project, Niepow M to Waldenberg G. C-B Package Boiler Systems. Milwaukee, WI, USA. June 9, 2003.
- Nett Technologies. 2003. Personal Communication with Jorge Santos. Nett Technologies, Inc., (905) 672-5453. Toronto, Ontario, Canada.
- NOXTECH. 2003. Personal Communication with Farzan Roshdieh. NOXTECH Inc., (949) 253-6087. Irvine, California, USA.

RJM-Beaumont. 2003. Proposal Number 106-01, Pulse-Clean Baghouse: 6 Oil-Fired Boilers, Willard Goss, RJM-Beaumont (TM) Environmental Systems, Pittsburgh, PA, April 9, 2003

Shultz. 1994. *Analysis of Power Loss Data for the 200 Area Tank Farms in Support of K Basin SAR Work*, WHC-EP-0811, December 1994. Schultz MV Jr., Westinghouse Hanford Company, Richland, Washington, USA.

Stegen. 1991. *HWVP Nitrogen Oxide Abatement Equipment Requirements Review*, WHC-SD-HWV-TI-013. Stegen G., Westinghouse Hanford Company, Richland, Washington, USA.

US Forest Service. 2000. *Federal Land Managers' Air Quality Related Work Group (FLAG), Phase 1 Report*. US Forest Service, National Park Service, and US Fish and Wildlife Service, Washington, DC, USA.

## **Appendix A**

### **State Environmental Policy Act Environmental Checklist for the River Protection Project - Waste Treatment Plant (24590-WTP-RPT-ENV-01-011, Rev 2)**



Document title: **State Environmental Policy Act  
Environmental Checklist for the  
River Protection Project - Waste  
Treatment Plant**

Contract number: DE-AC27-01RV14136  
Department: Environmental, Safety and Health  
Author(s): P Berlin

Principal author  
signature:

A handwritten signature in dark ink, appearing to read "P Berlin", written in a cursive style.

Document number: 24590-WTP-RPT-ENV-01-011, Rev. 2

Checked by: J Markillie

Checker signature:

A handwritten signature in dark ink, appearing to read "J Markillie", written in a cursive style.

Date of issue: 28 November 2001

Issue status: Approved

Approved by: B Erlandson

Approver's position: Environmental Permits Lead

Approver signature:

A handwritten signature in dark ink, appearing to read "B Erlandson", written in a cursive style.

ISSUED BY  
RPP-WTP PDC  
HE 11-29-01  
INIT DATE

River Protection Project  
Waste Treatment Plant  
3000 George Washington Way  
Richland, WA 99352  
United States of America  
Tel: 509 371 3500  
Fax: 509 371 3504





## History Sheet

Rev	Date	Reason for revision	Revised by
A	23 March 2000	Draft	J Sipkowski
0	31 March 2000	Approved	J Sipkowski
1	28 April 2000	Approved	J Sipkowski
A	13 June 2001	Draft for Review; Replaces RPT-W375-EN00014, Rev. 1	P Berlin
0	25 September 2001	Approved; Replaces RPT-24590-EN00010, Rev. A	P Berlin
1	24 October 2001	Changes made as a result of DOE review	P Berlin
2	28 November 2001	Incorporates DOE Signature	P Berlin



## Contents

Item	Page Number
<b>A Background.....</b>	<b>1</b>
<b>B Environmental Elements .....</b>	<b>4</b>
1. Earth .....	4
2. Air .....	6
3. Water .....	9
4. Plants.....	12
5. Animals .....	14
6. Energy and Natural Resources .....	15
7. Environmental Health .....	16
8. Land and Shoreline Use.....	18
9. Housing .....	20
10. Aesthetics .....	20
11. Light and Glare.....	21
12. Recreation.....	21
13. Historic and Cultural Preservation .....	21
14. Transportation .....	22
15. Public Services.....	23
16. Utilities .....	24
<b>References.....</b>	<b>25</b>

## Acronyms and Abbreviations

BNI	Bechtel National, Inc.
CFR	Code of Federal Regulations
DOE	US Department of Energy
DOE-RL	US Department of Energy, Richland Operations Office
EIS	Environmental Impact Statement
PM	particulate matter
TWRS	Tank Waste Remediation System
WAC	Washington Administrative Code
WTP	River Protection Project-Waste Treatment Plant

## A Background

1. **Name of proposed project, if applicable:**

The River Protection Project Waste Treatment Plant (WTP)

2. **Name of applicants:**

US Department of Energy, Office of River Protection  
US Department of Energy, Richland Operations Office

3. **Address and phone number of applicants and contact persons:**

US Department of Energy  
Office of River Protection  
P.O. Box 550  
Richland, Washington 99352

Mr. James Rasmussen, Director  
Environmental Management Division  
(509) 376-2247

4. **Date checklist prepared:**

September 2001

5. **Agency requesting the checklist:**

Washington State Department of Ecology  
Nuclear Waste Program  
1315 West 4th Avenue  
Kennewick, Washington 99336

6. **Proposed timing or schedule (including phasing, if applicable):**

Field construction activities are scheduled to begin in September of 2001. Construction of facility structures is scheduled to begin in November of 2002.

7. **Do you have any plans for future additions, expansion, or further activity related to or connected with this proposal? If yes, explain.**

The initial phase is to construct the WTP to treat approximately 10% of the volume of Hanford tank waste through the year 2018. A decision to modify, expand, or continue operation of the treatment and storage capacities in the facility could be made in the future with regulatory approval.

8. **List any environmental information you know about that has been prepared, or will be prepared, directly related to this proposal.**

The WTP concept was included in the *Tank Waste Remediation System, Final Environmental Impact Statement* (TWRS EIS; DOE 1996). The *Tank Waste Remediation System (TWRS) Record of Decision* (DOE 1997) was jointly issued by DOE and the Washington State

Department of Ecology to fulfill the environmental review requirements of the *National Environmental Policy Act of 1969* (NEPA 1969) and the *State Environmental Policy Act of 1971* (RCW 43.21). In addition, DOE approved the *Supplement Analysis for Tank Waste Remediation System* (Supplement Analysis 2; DOE 1998) and the *Mitigation Action Plan for the US Department of Energy, Hanford Site, Tank Waste Remediation System-Privatization, Phase I Facility Construction* (TWRS Mitigation Action Plan; DOE-RL 1998). Another supplement analysis is currently being written.

A *River Protection Project - Waste Treatment Plant Dangerous Waste Permit Application* (WTP Dangerous Waste Permit Application; BNFL 2000) was submitted by the Department of Energy to the Washington Department of Ecology on April 28, 2000. A revised Dangerous Waste Permit Application will be submitted in December 2001.

9. **Do you know whether applications are pending for government approvals of other proposals directly affecting the property covered by your proposal? If yes, explain.**

No known applications are pending for government approvals of other proposals directly affecting the proposed property.

10. **List any government approvals or permits that will be needed for your proposal, if known.**

The Washington State Department of Ecology is the lead agency authorized to approve the WTP Dangerous Waste Permit Application Part A, Form 3, and Part B for the WTP, pursuant to the requirements of Washington Administrative Code (WAC) 173-303-806, and the US Environmental Protection Agency Code of Federal Regulations, 40 CFR 270.

Emissions from the WTP will be permitted under:

- The State of Washington Department of Ecology Air Permit Regulations, WAC 173-400, 173-401, 173-460, and 173-480
- The State of Washington Department of Health radioactive air emissions licensing, WAC 246-247
- 40 CFR 52.21 and 40 CFR 61

Industrial waste water discharges, including the water generated from construction testing and storm water, will be permitted under the *Water Quality Standards for Ground Waters of the State of Washington*, WAC 173-200 and the *State Waste Discharge Permit Program*, WAC 173-216, as appropriate. Discharges from the sanitary sewer system will be permitted according to *On-Site Sewage Systems*, WAC 246-272.

The DOE Office of River Protection is responsible for overseeing nuclear and process safety for the WTP. To implement that responsibility, the Office of River Protection will review and approve the authorization basis prepared by Bechtel National Inc. (BNI), as required, for the design, construction, and operation of the WTP.

11. Give a brief, complete description of your proposal, including the proposed uses and the size of the project and site. There are several questions later in this checklist that ask you to describe certain aspects of your proposal. You do not need to repeat those answers on this page.

The WTP is proposed as a dedicated waste treatment and storage facility that will receive a mixed waste stream from Hanford's double-shell and single-shell tank farm systems. The waste will contain organic, inorganic, and radionuclide constituents. The facility will provide capabilities for vitrification treatment of low-activity waste (LAW) feed and high-level waste (HLW) feed. These feeds are subsets of high-level waste, which is defined in 10 CFR 72.3.

The feed treated in the LAW feed treatment process will primarily be the liquid supernatant portion of waste, with minor volumes of entrained solids, which at present is stored in the tank systems at the Hanford Site. The HLW feed treatment process will allow for the treatment of waste with a higher solids content.

12. Location of the proposal. Give sufficient information for a person to understand the precise location of your proposed project, including a street address, if any, and section, township, and range, if known. If a proposal would occur over a range of area, provide the range or boundaries of the site(s). Provide a legal description, site plan, vicinity map, and topographic map, if reasonably available. While you should submit any plans required by the agency, you are not required to duplicate maps or detailed plans submitted with any permit applications related to this checklist.

The WTP will be located in the 200 East Area of the Hanford Site, Benton County, Washington, on the Gable Butte, Washington, 7.5 minute quadrangle topographic map in section 3, T12N, R26E of the Willamette Base and Meridian. This location is in agreement with the comprehensive land use plan (DOE 1999a).

The WTP Dangerous Waste Permit Application (BNFL 2000) provides a small-scale map depicting the Hanford Site and the location of the WTP in Chapter 2, and a topographic map in Appendix 2A.

## B Environmental Elements

### 1. Earth

- a. **General description of the site (circle one): Flat, rolling, hilly, steep slopes, mountainous, other \_\_\_\_\_.**

The site is flat.

- b. **What is the steepest slope on the site (approximate percent slope)?**

The approximate slope of the land is less than two percent.

- c. **What general types of soils are found on the site (for example, clay, sandy gravel, peat, and muck)? If you know the classification of agricultural soils, specify them and note any prime farmland.**

Soil types for the 200 Areas of the Hanford Site are described in Volume I of the TWRS EIS, section 4.1.4 (DOE 1996). In general, soil types in the 200 Areas and around the WTP consist mainly of eolian and fluvial sands, and gravel. More detailed information concerning specific soil classifications can be found in *Hanford Site National Environmental Policy Act (NEPA) Characterization* (PNNL 2000). Farming is not permitted on the Hanford Site. The general area surrounding the Hanford Site 200 Areas was not farmed prior to construction of the Hanford facilities.

- d. **Are there surface indications or history of unstable soils in the immediate vicinity? If so, describe.**

No. The proposed WTP site is not located in an area of slope or soil instability, or in an area affected by unstable slope or soil conditions.

- e. **Describe the purpose, type, and approximate quantities of any filling or grading proposed. Indicate source of fill.**

Clearing and grading of land is the first activity in the sequence of construction and facility startup.

Approximately 450,000 cubic yards of earthworks is planned. Clearing and grading will be followed by excavation, compaction, and then facility construction.

An area below the grade slab will be fine-graded. Aggregate and fill for fine grading will be brought from quarry sites and borrow pits on or near the Hanford Site. Contaminated materials will not be used for fill.

**f. Could erosion occur as a result of clearing, construction, or use? If so, generally describe.**

Yes. During construction following initial disturbances and before revegetation, wind and storm water runoff erosion is possible. These conditions should be present only for a relatively short period of time. Land used only for construction purposes will either remain covered with aggregate or be restored to original condition and revegetated after construction.

Due to the possibility that the soil will be disturbed again for future work, construction laydown areas and other portions of the site will be reseeded using the appropriate standard Washington State Department of Transportation seed mix for revegetation in this climate, consistent with the TWRS Mitigation Action Plan (DOE-RL 1998). Infrastructure construction, such as transmission corridors, will be reseeded using a native grass and sagebrush seed mix.

A sizable portion of the WTP site, and also of nearby land, has previously been disturbed. Disturbance in the surrounding areas includes the construction of roads, processing facilities, pipelines, and other facilities and infrastructure associated with the production of plutonium and waste management. The impact from the grading activities on surface or near surface geologic features will be confined to small, localized topographic changes where facilities are constructed.

**g. About what percent of the site will be covered with impervious surfaces after project construction (for example, asphalt or buildings)?**

A total of approximately 119.2 acres of land will be used for the construction of the WTP.



Approximately 64 acres will be occupied by the operational WTP and potentially covered with an impervious surface. Approximately 4.2 acres will be used for septic leach fields, which will be allowed to revegetate naturally. The remaining 51 acres will be used temporarily during construction for workforce parking, lay down area, and stockpiling. Small portions of the construction area may be covered with concrete or asphalt to provide material storage and temporary construction offices. These concrete or asphalt areas will remain upon completion of construction.

**h. Proposed measures to reduce or control erosion, or other impacts to the earth, if any:**

- Gravel and dust suppression techniques (for example, watering and the application of degradable soil fixatives) will help control erosion in the construction area.
- Land used only for construction purposes will either remain covered with aggregate or be restored to original condition and revegetated after construction.
- Due to the possibility that the soil will be disturbed again for future work, construction laydown areas will be reseeded using the appropriate standard Washington State Department of Transportation seed mix for revegetation in this climate, consistent with the TWRS Mitigation Action Plan (DOE-RL 1998).

**2. Air**

**a. What types of emissions to the air would result from the proposal (such as, dust, automobile, odors, and industrial wood smoke) during construction and when the project is completed? If any, generally describe and give approximate quantities, if known.**

Air emissions as a result of construction activities are estimated, in the TWRS-EIS (DOE 1996) Volume 5, Appendix G, to be:

Criteria pollutants	Emissions in grams per
Sulfur oxides	0.19
Nitrogen oxides	8.6
Carbon monoxide	46
Particulate matter (PM-10)	6.8

**24590-WTP-RPT-ENV-01-011, Rev. 2**  
**State Environmental Policy Act Environmental Checklist for**  
**the River Protection Project - Waste Treatment Plant**

<u>Hazardous pollutants</u>	<u>Emissions in grams per second</u>
Formaldehyde	$3.5 \times 10^{-5}$

Air emissions from plant operations, excluding steam boilers, are estimated in the *Integrated Emissions Baseline Report for the River Protection Project Waste Treatment Plan* (BNI 2001). The tables below summarize the information for: criteria pollutants; and total organic pollutants, inorganic pollutants, and radionuclide emissions.

<u>Criteria pollutants</u>	<u>Emissions in grams per second</u>
Sulfur oxides	$1.4 \times 10^{-4}$
Nitrogen oxides	0.43
Carbon monoxide	0.43
PM-10	$1.6 \times 10^{-4}$

<u>Pollutant</u>	<u>Emissions</u>
Total organic carbon	0.29 tons per year
Inorganics	0.87 grams per second
Radionuclides	2.71 curies per day

Air emissions from steam boilers are estimated to be:

<u>Criteria pollutants</u>	<u>Emissions in tons per year</u>
SO <sub>x</sub>	31.99
NO <sub>x</sub>	113.46
CO	27.96
PM-10	9.27
Volatile organic compounds	2.00

These emission estimates will be verified as the design progresses. Emissions from the treatment facility will be regulated under the appropriate permits as presented in section A.10.

- b. **Are there any offsite sources of emissions or odors that may affect your proposal? If so, generally describe.**

No.

- c. **Proposed measures to reduce or control emissions or other impacts to the air, if any?**

Dust control measures will be applied during construction to reduce fugitive dust emissions. These measures may include watering or application of dust control chemicals, as well as temporary seeding and revegetation. The primary and secondary offgas controls specified for the WTP designs are expected to result in emissions that would be substantially below both federal and state standards in all areas open to the public.

Commercially available treatment systems will treat the steam boiler and standby generator emissions to levels compliant with applicable standards.

In addition, good engineering practices will be followed, and actions would comply with procedures designed to protect human health and the environment. Administrative control practices will limit air emissions and protect worker health.

### 3. Water

#### a. Surface

- 1) **Is there any surface water body on or in the immediate vicinity of the site (including year-round and seasonal streams, saltwater, lakes, ponds, and wetlands)? If yes, describe type and provide names. If appropriate, state what stream or river it flows into.**

There is no surface water body on or in the immediate vicinity of the WTP. Additional information can be found in the TWRS-EIS, Section 4.2.1.

- 2) **Will the project require any work over, in, or adjacent to (within 200 feet) the described waters? If yes, please describe and attach available plans.**

No.

- 3) **Estimate the amount of fill and dredge material that would be placed in or removed from surface water or wetlands and indicate the area of the site that would be affected. Indicate the source of fill material.**

None. There will be no dredging or filling from, or to, surface water or wetlands.

- 4) **Will the proposal require surface water withdrawals or diversions? Give general description, purpose, and approximate quantities if known.**

The water supply for the 200 Areas is pumped from the Columbia River. The WTP will use raw water at approximately 875 US gallons per minute, based on an annual average. The water will primarily be used in cooling towers and will also be used for reagent make-up and plant and equipment wash down.

- 5) **Does the proposal lie within a 100-year floodplain? If so, note location on the site plan.**

The WTP is not within the 100-year floodplain.

- 6) Does the proposal involve any discharges of waste materials to surface waters? If so, describe the type of waste and anticipated volume of discharge.

No.

b. Ground

- 1) Will ground water be withdrawn, or will water be discharged to ground water? Give general description, purpose, and approximate quantities if known.

No groundwater will be withdrawn in support of the project, nor will water be discharged directly to the aquifer from the WTP. The project is governed by three Hanford site-wide permits that allow water to be discharged to the ground at the WTP. These discharges will include hydrotesting, maintenance, and construction discharges, cooling water condensate, and stormwater. Liquids may also be transferred to other permitted facilities (for example, the Effluent Treatment Facility and the Treated Effluent Disposal Facility) that will treat effluent prior to its discharge to the ground. The depth to groundwater at the WTP is over 260 feet. Sanitary sewage will be discharged to permitted leach fields.

In addition to the three discharge sources identified above, process water and stormwater will be discharged from the concrete batch plant. These discharges will be during construction of the WTP and are covered by a sand and gravel general permit.

- 2) Describe waste material that will be discharged into the ground from septic tanks or other sources, if any (for example: Domestic sewage; industrial, containing the following chemicals... agricultural; and so forth). Describe the general size of the system, the number of such systems, the number of houses to be served (if applicable), or the number of animals or humans the system(s) are expected to serve.

During construction, approximately 48,000 US gallons per day of sanitary waste will be disposed of in onsite septic leach fields, based on a construction work force of approximately 3200. During operations, approximately 29,000 US gallons per day of sanitary waste will be discharged to septic leach fields from an operational work force of approximately 1110. Anticipated discharges to the ground will be from construction activities, which include:

- stormwater
- dust mitigation
- concrete work
- tank and pipe hydrotesting
- construction operations

c. **Water Runoff (including storm water)**

- 1) Describe the source of runoff (including storm water) and method of collection and disposal, if any (include quantities, if known). Where will this water flow? Will this water flow into other waters? If so, describe.

The Hanford Site receives an average of six to seven inches of annual precipitation. The primary source of runoff associated with this project will be storm water from the buildings, paved areas, and other impervious surfaces of the plant. The light and infrequent nature of precipitation at the site will produce correspondingly light runoff from the impervious surfaces. The precipitation will not come into contact with any of the mixed waste being stored in the facility. Storm water will be managed in

accordance with an approved permit, as  
presented in section A.10.

- 2) **Could waste materials enter ground or  
surface waters? If so, generally describe.**

Waste materials will not enter ground or  
surface waters. Waste materials will be  
primarily contained in buildings with roofs  
to prevent contact with storm water and  
ground or surface water. Two tanks  
containing waste will be located outside of  
buildings. These tanks will have secondary  
containment with protective coating to  
prevent waste from entering ground or  
surface waters.

- d. **Proposed measures to reduce or control surface,  
ground, and runoff water impacts, if any:**

No surface, ground, or runoff water impacts are  
expected. A Stormwater Pollution Prevention Plan  
and an Erosion and Sediment Control Plan are  
required by the sand and gravel permits. These  
plans will be written to utilize and incorporate the  
Best Management Practices Plan for Hanford Site  
permits

#### 4. Plants

- a. **Check or circle the types of vegetation found on  
the site.**

☐ deciduous tree: alder, maple, aspen, other  
☐ evergreen tree: fir, cedar, pine, other  
☒ shrubs  
☒ grass  
☐ pasture  
☐ crop or grain  
☐ wet soil plants: cattail, buttercup, bulrush,  
skunk cabbage, other  
☐ water plants: water lily, eelgrass, milfoil,  
other  
☒ other types of vegetation

The most common native vegetation community in  
the vicinity of the WTP is the sagebrush and bunch  
grass community. Numerous species of sagebrush  
and a variety of bunch grass species are found on the  
Hanford Site. Disturbed areas are commonly  
populated by cheat grass, *Bromus tectorum*.

- b. **What kind and amount of vegetation will be removed or altered?**

Section 4.4 in Volume I of the TWRS EIS (DOE 1996) describes the vegetation in the vicinity of the WTP. Acreage taken by the WTP is inside the portion of the Hanford Site dedicated to long-term waste management under the *Hanford Comprehensive Land-Use Plan Environmental Impact Statement* (DOE 1999a). Substantial portions of the 119.2-acre site have been previously disturbed by clearing, grading, or other activities and are poor-quality habitat. Nevertheless, clearing and grading will remove and alter shrub-steppe vegetation and habitat.

The Supplement Analysis 2 (DOE 1998) states that 37 acres in the area of the proposed site have previously been disturbed. The TWRS EIS (DOE 1996) assumes that 62 percent of the area that would be used for construction and operation for the WTP would disturb previously undisturbed shrub-steppe habitat. Based on the current 119.2 acres requested (64 acres for operations, 4.2 acres for septic leach fields, and 51 acres for construction) and the information in the Supplement Analysis 2 (DOE 1998), it is estimated that 51 acres ( $119.2 - 37 = 82.2$  acres;  $0.62 \times 82.2 =$  approximately 51 acres) of previously undisturbed land will be taken.

Plant species likely to be taken would include big sagebrush and gray rabbit brush, dominant species in the Hanford Site shrub-steppe habitat. While not known to exist on the WTP site, potentially affected species of concern that could be present, according to the TWRS EIS Volume I, section 4.4.2 (DOE 1996), include crouching milkvetch, stalk-pod milkvetch, scilla onion, and Piper's daisy.

- c. **List threatened or endangered species known to be on or near the site.**

None. No federally-listed threatened or endangered plant or animal species are known to occur on or near the Central Plateau, where the WTP site is located. Additional information is provided in Volume I of the TWRS EIS, sections 4.4.4 and 4.4.5 (DOE 1996).



The Hanford Site contains some federally and state-listed threatened and endangered plant and animal species. Additional information on species can be found in the *Hanford Site National Environmental Policy Act (NEPA) Characterization* (PNNL 2000).

- d. **Proposed landscaping, use of native plants, or other measures to preserve or enhance vegetation on the site, if any:**

DOE has committed to compensate for biological and natural resource disturbance caused by construction activities of the WTP at an appropriate site to be determined by the DOE. Furthermore, due to the possibility that the soil at the site will be disturbed again for future work, construction laydown areas and other portions of the site will be reseeded, using the appropriate standard Washington State Department of Transportation seed mix for revegetation in this climate. Additional information is provided in Volume I of the TWRS EIS, section 5.20 (DOE 1996), and the TWRS Mitigation Action Plan (DOE-RL 1998).

## 5. Animals

- a. **Indicate (by underlining) any birds and animals which have been observed on or near the site or are known to be on or near the site.**

The following (as indicated by underlining) have been observed on or near the site or are known to be on or near the site:

birds: hawk, heron, eagle, songbirds, other  
mammals: deer, bear, elk, beaver, other  
fish: bass, salmon, trout, herring, shellfish, other

Raptors (for example, burrowing owls, ferruginous, red-tail, and Swainson's hawks) are seen occasionally in the 200 East Area. Small passerines (for example, sparrows, finches) also are present in the general vicinity of the WTP. Two Washington State candidate bird species were observed in the vicinity during the performance of a biological review of the proposed location of the WTP: the loggerhead shrike (*Lanius ludovicianus*) and the sage sparrow (*Amphispiza belli*) (PNNL 1999). Mule deer, rabbits, badgers, and coyotes occasionally are seen in the general area. Additional

information is provided in Volume I of the TWRS EIS, sections 4.4.3, and 4.4.5 (DOE 1996).

- b. **List any threatened or endangered species known to be on or near the site.**

Two federally and state-listed threatened or endangered species have been identified on the 560 square mile Hanford Site along the Columbia River: the bald eagle and the peregrine falcon. In addition, the state-listed white pelican, sandhill crane, and ferruginous hawk also occur on or migrate through the Hanford Site. Of these 5 species, only the ferruginous hawks have been seen on occasion in the general area. These hawks have not been observed to use the habitat in the vicinity of the WTP for perching, hunting, or nesting. The sage sparrow (*Amphispiza belli*) and the loggerhead shrike (*Lanius ludovicianus*), two Washington State Candidate bird species, were observed in the vicinity of the proposed location of the WTP.

Additional information is provided in Volume I of the TWRS EIS, section 4.4.5 (DOE 1996).

- c. **Is the site part of a migration route? If so, explain.**

The Hanford Site is a part of the broad Pacific Flyway.

- d. **Proposed measures to preserve or enhance wildlife, if any:**

Specific measures to preserve or enhance wildlife are discussed in section 5.20 of Volume I of the TWRS EIS (DOE 1996) and the TWRS Mitigation Action Plan (DOE-RL 1998).

## **6. Energy and Natural Resources**

- a. **What kinds of energy (electric, natural gas, oil, wood stove, solar) will be used to meet the completed project's energy needs? Describe whether it will be used for heating, manufacturing, and so forth.**

Energy needs for the WTP are presented in the TWRS-EIS, Volume I, Table 5.16.1. Electrical and oil energy will be used for heating and to support operation of the treatment facility.

- b. **Would your project affect the potential use of solar energy by adjacent properties? If so, generally describe.**

No.

- c. **What kinds of energy conservation features are included in the plans of this proposal? List other proposed measures to reduce or control energy impacts, if any:**

A pollution prevention plan that includes elements of sustainable design, and pollution prevention opportunity assessments, will be implemented to identify methods to reduce energy use and minimize waste. Systems will be operated to use energy and resources in the most efficient manner possible.

## **7. Environmental Health**

- a. **Are there any environmental health hazards, including exposure to toxic chemicals, risk of fire and explosion, spill, or hazardous waste, that could occur as a result of this proposal? If so, describe.**

Possible environmental health hazards to workers could arise from activities at the WTP. The hazard could come from exposure to radioactive, dangerous, or mixed waste. Engineered barriers and administrative controls are used to minimize the probability of even a minor incident or accident. A chemical spill, release, fire, or explosion could occur only as a result of a simultaneous breakdown in multiple barriers or a catastrophic natural event.

- 1) **Describe special emergency services that might be required.**

Special emergency services might be required for circumstances involving mixed waste incidents, such as spills, releases, fires, and explosions.

- 2) **Proposed measures to reduce or control environmental health hazards, if any:**

All personnel will be trained to follow proper procedures during the WTP treatment and storage operations to minimize potential

exposure. The WTP will have systems for air emission controls, radiation monitoring, fire protection, and alarm capability. The ventilation system will maintain a negative air pressure in operations buildings.

The WTP will have measures in place to reduce or control environmental health hazards. These measures will include containment structures and equipment, protective equipment and clothing, and operating procedures to ensure that hazards are minimized. The physical security of a chain-link fence around the WTP and limited access to authorized personnel will further reduce potential exposures.

**b. Noise**

- 1) What type of noise exists in the area which may affect your project (for example: traffic, equipment, operation, other)?**

The site is characterized by background noise from traffic and activities taking place in the 200 East Area. The project is not noise-sensitive.

- 2) What types and levels of noise would be created by or associated with the project on a short-term or a long-term basis (for example: traffic, construction, operations, other)? Indicate what hours noise would come from the site.**

During construction, noise will largely be generated by mechanized equipment such as loaders, bulldozers, cranes, and trucks. Noise levels from all mechanized equipment used during construction activities will be within the General Services Administration construction noise specifications or other similar noise standards (29 CFR 1910.95). Noise from construction activities will primarily be during daylight hours.

Because the waste treatment process equipment will be operating inside enclosed structures, exterior noise levels will not be substantially increased due to the WTP.

Minor amounts of noise from traffic and equipment are expected during day-shift hours during operations. For additional information, refer to the TWRS EIS (DOE 1996).

3) **Proposed measures to reduce or control noise impacts, if any:**

If Occupational Safety and Health Administration noise standards are exceeded, appropriate measures to protect workers will be employed.

**8. Land and Shoreline Use**

a. **What is the current use of the site and adjacent properties?**

The site consists of disturbed and undisturbed sagebrush. The subject site is adjacent to the 241-AP Tank Farm and generally flat, with a spoils pile near the center. The spoils pile is soil from the construction of the adjacent grout vaults.

b. **Has the site been used for agriculture? If so, describe.**

No portion of the 200 Areas has been used for agricultural purposes since 1943, if ever.

c. **Describe any structures on the site.**

As of September 2001, power distribution facilities, a visitor trailer, and a construction trailer have been located at the WTP site.

d. **Will any structures be demolished? If so, what?**

No structures are to be demolished.

e. **What is the current zoning classification of the site?**

The Hanford Site is zoned as an Unclassified Use District by Benton County, Washington.

f. **What is the current comprehensive plan designation of the site?**

*The Record of Decision: Hanford Comprehensive Land-Use Plan Environmental Impact Statement* (DOE 1999b) designated the 200 Areas as "Industrial Exclusive", dedicated to nuclear waste management activities.

- g. **If applicable, what is the current shoreline master program designation of the site?**

Does not apply.

- h. **Has any part of the site been classified as an "environmentally sensitive" area? If so, specify.**

No part of the WTP site has been classified as an "environmentally sensitive" area. The 200 Areas, in particular, is located in a previously disturbed industrial area of little or no environmental significance. There will be an environmental impact to the shrub steppe habitat from construction activities. The State of Washington Department of Fish and Wildlife has designated the shrub steppe as a "priority habitat" (PNNL 2000). Mitigation has been performed in accordance with the TWRS Mitigation Action Plan (DOE-RL 1998) developed by DOE in accordance with department policy. Additional information is provided in Volume I of the TWRS EIS, section 4.0 (DOE 1996).

- i. **Approximately how many people would reside or work in the completed project?**

Employment during peak construction will be approximately 2,700 full-time equivalents onsite. About 500 additional personnel (for example, engineers, designers, managers, and support personnel) will be located in office facilities in the Tri-Cities area. Approximately 1110 onsite workers are expected during operations.

- j. **Approximately how many people would the completed project displace?**

None. Refer to Volume I of the TWRS EIS, section 5.6.1 (DOE 1996), for additional information.

- k. **Proposed measures to avoid or reduce displacement impacts, if any:**

Does not apply.

- l. **Proposed measures to ensure the proposal is compatible with existing and project land uses and plans, if any:**

Does not apply.

## 9. Housing

- a. **Approximately how many units would be provided, if any? Indicate whether high, middle, or low-income housing.**

None. Refer to Volume I of the TWRS EIS, section 5.6.2 (DOE 1996), for additional information.

- b. **Approximately how many units, if any, would be eliminated? Indicate whether high, middle, or low-income housing.**

None.

- c. **Proposed measures to reduce or control housing impacts, if any:**

None.

## 10. Aesthetics

- a. **What is the tallest height of any proposed structure(s), not including antennas; what is the principal exterior building material(s) proposed?**

The tallest building of the WTP will be approximately 140 feet above grade, and the tallest stack will be approximately 200 feet. The principal exterior building material will be sheet metal.

- b. **What views in the immediate vicinity would be altered or obstructed?**

None.

- c. **Proposed measures to reduce or control aesthetic impacts, if any:**

None. Refer to Volume I of the TWRS EIS, section 5.20 (DOE 1996), for additional information.

## 11. Light and Glare

- a. What type of light or glare will the proposal produce? What time of day would it mainly occur?

Lighting will be provided for the proposed site during construction and operations during the day and night.

- b. Could light or glare from the finished project be a safety hazard or interfere with views?

No.

- c. What existing offsite sources of light or glare may affect your proposal?

None.

- d. Proposed measures to reduce or control light and glare impacts, if any:

None.

## 12. Recreation

- a. What designated and informal recreational opportunities are in the immediate vicinity?

None.

- b. Would the proposed project displace any existing recreational uses? If so, describe.

No.

- c. Proposed measures to reduce or control impacts on recreation, including recreation opportunities to be provided by the project or applicant, if any?

None.

## 13. Historic and Cultural Preservation

- a. Are there any places or objects listed on, or proposed for, national, state, or local preservation registers known to be on or next to the site? If so, generally describe.



Portions of the Hanford Site were included in land designated as the Hanford Reach National Monument in June 2000. Land on or adjacent to the WTP is not included in this designation. Refer to Volume I of the TWRS EIS, section 5.5 (DOE 1996), and the *Hanford Site National Environmental Policy Act (NEPA) Characterization* (PNNL 2000) for additional information.

- b. **Generally describe any landmarks or evidence of historic, archaeological, scientific, or cultural importance known to be on or next to the site.**

There are no known landmarks or evidence of historic, archaeological, scientific, or cultural importance at the WTP site (PNNL 1998) and (PNNL 2000).

- c. **Proposed measures to reduce or control impacts, if any:**

Does not apply.

#### 14. Transportation

- a. **Identify public streets and highways serving the site, and describe proposed access to the existing street system. Show onsite plans, if any.**

Access to the WTP site is via DOE-provided highways and roads. There will be no public access to the WTP. A small-scale map is provided in Chapter 2 of the WTP Dangerous Waste Permit Application (BNFL 2000), depicting the Hanford Site and the location of the WTP. The map also identifies public streets and highways that connect to the DOE-owned Hanford Site roads.

- b. **Is the site currently served by public transit? If not, what is the approximate distance to the nearest transit stop?**

The WTP will not be accessible to the public and will not be served by public transit. The nearest public transit stop is approximately 20 miles from the WTP.

- c. **How many parking spaces would the completed project have? How many would the project eliminate?**

The WTP will provide 320 parking spaces. Because the proposed site is currently undeveloped, no parking will be eliminated as a result of this project.

- d. **Will the proposal require any new roads or streets, or improvements to existing roads or streets, not including driveways? If so, generally describe (indicate whether public or private).**

Yes. An access road will be constructed from Canton Avenue to the WTP site. The road will be accessible only to authorized personnel.

- e. **Will the project use (or occur in the immediate vicinity of) water, rail, or air transportation? If so, generally describe.**

No.

- f. **How many vehicular trips per day would be generated by the completed project? If known, indicate when peak volumes would occur.**

The Supplement Analysis 2 (DOE 1998), section 4.11, states that traffic impacts associated with the construction and operation of the WTP would be similar to those analyzed in the TWRS-EIS, Volume 1, section 5.10 (DOE 1996). The morning peak hour traffic volume would be approximately 5600 vehicles. Refer to the Supplement Analysis 2 and the TWRS-EIS for additional information.

- g. **Proposed measures to reduce or control transportation impacts, if any:**

Volume I of the TWRS EIS, section 5.20.2 (DOE 1996), discusses widening Route 4 west of the Wye Barricade, or reducing the speed limits on Route 4 as potential mitigation measures that may be deemed necessary.

## **15. Public Services**

- a. **Would the project result in an increased need for public services (for example: fire protection, police protection, health care, schools, other)? If so, generally describe.**

The increased population resulting from the construction and operation of the WTP is expected to place additional demands on public facilities and

services. Refer to the Volume I of the TWRS EIS, section 5.6.3 (DOE 1996), for additional information.

- b. **Proposed measures to reduce or control direct impacts on public services, if any:**

Volume 1 of the TWRS-EIS, section 5.20 (DOE 1996), does not identify any mitigation measures to reduce or control the impacts of the WTP on public services.

## 16. Utilities

- a. **Circle utilities currently available at the site: electricity, natural gas, water, refuse service, telephone, sanitary sewer, septic system, other:**

There are no utilities currently available on the WTP site.

- b. **Describe the utilities that are proposed for the project, the utility providing the service, and the general construction activities on the site or in the immediate vicinity which might be needed.**

The water is provided to the facility from extensions of the 200 Areas potable and raw water systems. The water system extensions proceed east to the WTP from existing pipelines in the vicinity of Canton Street in the 200 East Area.

Electricity is provided to the WTP from a new substation built to support the WTP. The substation has a capacity of 62.5 megawatts.

Oil storage may be added as part of the project.

## References

10 CFR 72.3. *Licensing Requirements for the Independent Storage of Spent Nuclear Fuel and High-Level Radioactive Waste*, as amended. Code of Federal Regulations.

29 CFR 1910.95. *Occupational Noise Exposure*, as amended. Code of Federal Regulations.

40 CFR 52.21. *Prevention of Significant Deterioration of Air Quality*, as amended. Code of Federal Regulations.

40 CFR 61. *National Emission Standards for Hazardous Air Pollutants*, as amended. Code of Federal Regulations.

40 CFR 270. *EPA Administered Permit Programs: The Hazardous Waste Permit Program*, as amended. Code of Federal Regulations.

BNFL. 2000. *River Protection Project - Waste Treatment Plant Dangerous Waste Permit Application*, BNFL-5193-RCRA-01, Revision 2. 28 April 2000. BNFL Inc., Richland, Washington, USA.

BNL. 2001. *Integrated Emissions Baseline Report for the River Protection Project Waste Treatment Plant*, RPT-W375-ES00001, Revision 1. May 2001. Bechtel National Inc., Richland, Washington, USA.

DOE. 1996. *Tank Waste Remediation System, Hanford Site, Richland, Washington, Final Environmental Impact Statement*, DOE/EIS-0189, August 1996. US Department of Energy, Washington, DC, USA.

DOE. 1997. *Tank Waste Remediation System (TWRS) Record of Decision (ROD)*, Federal Register Volume 62 pp. 8693-8704. 62 FR 8693, February 27, 1997.

DOE. 1998. *Supplement Analysis for the Tank Waste Remediation System*, DOE/EIS-0189-SA2, May 1998. US Department of Energy, Washington, DC, USA.

DOE. 1999a. *Hanford Comprehensive Land-Use Plan Environmental Impact Statement*. DOE/EIS-0222-F, September 1999. US Department of Energy, Washington, DC, USA.

DOE. 1999b. *Record of Decision: Hanford Comprehensive Land-Use Plan Environmental Impact Statement*. Federal Register, Vol. 64, No. 218. 12 November 1999.

DOE-RL. 1998. *Mitigation Action Plan for the US Department of Energy, Hanford Site, Tank Waste Remediation System-Privatization, Phase I Facility Construction*, May 1998. US Department of Energy, Richland Operations Office, Richland, Washington, USA.

NEPA. 1969. *National Environmental Policy Act of 1969*. 42 United States Code 4321 et seq.

PNNL. 1998. Letter from Hale LL, PNNL to Kjarmo K, FDH, *Cultural Resources Review of the TWRS Mitigation Planning Support-Phase One Project*, HCRC #98-0200-022, May 22, 1998. Pacific Northwest National Laboratory, Richland, Washington, USA.

PNNL. 2000. *Hanford Site National Environmental Policy Act (NEPA) Characterization*, PNL-6415, Revision 12. September 2000. Pacific Northwest National Laboratory, Richland, Washington, USA.

RCW. 43.21. *State Environmental Policy Act of 1971*, Chapter 43.21C. Revised Code of Washington.

WAC 173-200. *Water Quality Standards for Ground Waters of the State of Washington*, as amended. Washington Administrative Code.

WAC 173-216. *State Waste Discharge Permit Program*, as amended. Washington Administrative Code.

WAC 173-303. *Dangerous Waste Regulations*, as amended. Washington Administrative Code.

WAC 173-400. *General Regulation for Air Pollution Sources*, as amended. Washington Administrative Code.

WAC 173-401. *Operating Permit Regulation*, as amended. Washington Administrative Code.

WAC 173-460. *Controls for New Sources of Toxic Air Pollutants*, as amended. Washington Administrative Code.

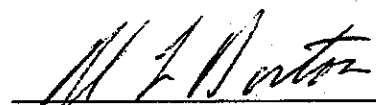
WAC 173-480. *Ambient Air Quality Standards and Emission Limits for Radionuclides*, as amended. Washington Administrative Code.

WAC 246-247. *Radiation Protection – Air Emissions*, as amended. Washington Administrative Code.

WAC 246-272. *On-Site Sewage Systems*, as amended. Washington Administrative Code.

**SIGNATURES**

The above answers are true and complete to the best of my knowledge.



Harry L. Boston, Manager  
US Department of Energy  
Office of River Protection



Date

## **Appendix B**

### **Calculation Sheet: Emission Estimate for Revision 1, Prevention of Significant Deterioration Permit Application (24590-WTP-HAC-50-00006, Rev A)**



# Calculation Cover Sheet

ISSUED BY  
RPP-WTP-DOC  
10-6-18-03  
INT DATE

Sheet i

RIVER PROTECTION PROJECT-WASTE TREATMENT PLANT				JOB NO.: 24590			
CALC NO. 24590-WTP-HAC-50-00006, Rev. A				GROUP E&NS Environmental Permitting			
SUBJECT Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1							
CALCULATION STATUS <input checked="" type="checkbox"/> PRELIMINARY <input type="checkbox"/> COMMITTED <input type="checkbox"/> CONFIRMED							
DESIGNATION <input type="checkbox"/> SUPERSEDED <input type="checkbox"/> VOIDED							
SOFTWARE APPLICATION	N/A <input checked="" type="checkbox"/>	QAS <input type="checkbox"/> YES <input type="checkbox"/> NO	PROGRAM NAME			VERSION/RELEASE NO.	
<p>Notes/Comments</p> <p>Software Tools:</p> <ol style="list-style-type: none"><li>1. Microsoft Excel</li><li>2. MathCad</li></ol> <p>The above software applications are considered "Tools" in accordance with 24590-WTP-3DP-G04B-00037, Rev. 3, <i>Engineering Calculations</i>; therefore, they are not subject to Section 3.3.1 requirements of that procedure. In addition, because these applications are considered Tools, the Software Application row of this Calculation Cover Sheet is marked "N/A".</p> <p>Originator – Stan Hill Checker – Bob Haggard Approver – Phil Peistrup</p>							
A	Preliminary Calculation	37	37	S. Hill	B. Haggard	P. Peistrup	6/18/03
NO.	REASON FOR REVISION	TOTAL NO. OF SHEETS	LAST SHEET NO.	BY	CHECKED	APPROVED/ACCEPTED	DATE
RECORD OF REVISIONS							



# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 1

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

## Contents

1	Objective.....	2
2	Inputs .....	2
3	Background .....	2
4	Applicable Codes and Standards .....	2
5	Methodology .....	2
5.1	Estimates of PSD Regulated Constituent Emissions from Pretreatment and Vitrification Processes .....	2
5.2	Estimates of PSD Regulated Constituent Emissions for the Balance of Facilities .....	3
6	Assumptions .....	3
7	Calculations .....	4
7.1	Determination of Annual Boiler NOx Emission Rates .....	4
7.2	Determination of Boiler NOx Emission Concentration .....	5
7.3	Determination of Annual Generator NOx Emission Rates .....	5
7.4	Determination of Generator NOx Emission Concentration .....	6
7.5	Determination of Fire Water Pump NOx Emission Rate.....	8
7.6	Determination of Fire Water Pump NOx Emission Concentration .....	9
7.7	Emission Rate from Glass Former Facility .....	11
7.8	Determination of LAW Vitrification Process NOx Emission Concentration .....	12
7.9	Determination of Pretreatment Process & Vessel Vent NOx Emission Concentration.....	15
8	Results and Conclusion .....	18
9	References.....	18
10	Attachments.....	18

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 2

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

## 1 Objective

This calculation is prepared to support the Prevention of Significant Deterioration (PSD) Permit Application (24590-WTP-RPT-ENV-01-007, Rev 1). The calculation presents the methodologies and assumptions used to determine the PSD regulated criteria pollutant air emissions from the Hanford Tank Waste Treatment and Immobilization Plant (WTP). Section 7 Calculations provides example calculations of NO<sub>x</sub> emissions. The methods used to calculate particulate matter emissions are identical to those used to calculate NO<sub>x</sub> emissions.

## 2 Inputs

The below are the inputs to the calculation.

1. 24590-LAW-M4C-20-00001, Rev. A, *LAW Mass Heat and Pressure Balance Calculation*
2. 24590-HLW-M4C-30-00001, Rev. A, *HLW Mass Heat and Pressure Balance Calculation*
3. 24590-WTP-MRQ-PO-03-002, Rev. 0, *Emission Maximum Case Runs with Updated Parameters*
4. 24590-PTF-MKC-PVP-00001, Rev B, *Radiolytic NO<sub>x</sub> Evolution in PT High Activity Process Vessels (Revised)*
5. Vendor bid packages (see attachment B)
6. 24590-PTF-M5-V17T-00021001, Rev. 0, *Process Flow Diagram Pretreatment Vessel Vents Process (PJV) System PVP/PVV/PJV*
7. 24590-PTF-MAC-PVV-00001, Rev 0, *Vessel Vent Exhaust System Equipment Selection*

## 3 Background

NA.

## 4 Applicable Codes and Standards

NA.

## 5 Methodology

### 5.1 Estimates of PSD Regulated Constituent Emissions from Pretreatment and Vitrification Processes

The PSD regulated constituent emissions from pretreatment and the vitrification processes were estimated using a computer model - the Aspen Custom Modeler (ACM). The resulting emission data is documented in the Emission Maximum Case Runs with Updated Parameters - 24590-WTP-MRQ-PT-03-002, Rev. 0.

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

BY: J. Stan Hill

DATE: 6/17/03

SHEET REV: A

SHEET NO.: 3

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

## 5.2 Estimates of PSD Regulated Constituent Emissions for the Balance of Facilities

Balance of Facilities (BOF) operations that result in emissions of PSD regulated constituents include steam boilers, internal combustion engines (generators and diesel engine driven fire water pumps), and the glass former storage facility. The emissions of PSD regulated constituents were calculated based on engineering estimates of hours of operation, capacity of equipment, and available emission factors.

## 6 Assumptions

General assumptions and other applicable data applied within this calculation include:

- Ultra low sulfur fuel (0.003% by weight of sulfur) will be used for the steam boilers, generators and diesel engines for the fire water pumps.
- The particulate matter from WTP is assumed to be PM<sup>10</sup>.

Assumptions associated with specific emission sources described in Section 7 include:

Section  
Number

- 7.1 Determination of Annual Boiler NOx Emission Rates
  - 3 boilers operating at 8760 hours per year represented as Boiler\_1\_number := 3
  - 3 boilers operating at 3679 hours per year represented as Boiler\_2\_number := 3
- 7.2 Determination of Boiler NOx Emission Concentration
  - Boiler exhaust flow rate is 10,065 ft<sup>3</sup> per minute
- 7.3 Determination of Annual Generator NOx Emission Rates
  - One Type I generators at 3950 horsepower represented as Generator\_1\_number := 1
  - Two Type II generators at 5530 horsepower represented as Generator\_2\_number := 2
- 7.4 Determination of Generator NOx Emission Concentration
  - Generator exhaust flow rate is 15,204 ft<sup>3</sup> per minute
- 7.5 Determination of Annual Fire Water Pump NOx Emission Rates
  - Two fire water pumps operating at 110 hours per year represented as Pump\_number := 2
- 7.6 Determination of Fire Water Pump NOx Concentration
  - Fire water pump exhaust flow rate is 1,642 ft<sup>3</sup> per minute
- 7.7 Emission Rate from Glass Formers Storage Building
  - Glass former throughput is 105,200 lbs per day
- 7.8 Determination of LAW Vitriification Process NOx Emission Concentration
  - LAW vitriification exhaust flow rate is 5,992 ft<sup>3</sup> per minute

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 4

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

## 7 Calculations

The following sections provide example calculations for emission rates and concentrations associated with the following WTP emission sources for PSD regulated constituents:

- Boilers
- Generators
- Fire Water Pumps
- Glass Formers Storage Building
- WTP Vitrification Processes

All calculated concentrations are expressed in standard temperature and pressure (STP) converted to dry STP.

### 7.1 Determination of Annual Boiler NOx Emission Rates

Boiler\_1\_number := 3 (3 boilers operating at 8760 hours per year)

Boiler\_2\_number := 3 (3 boilers operating at 3679 hours per year)

#### Annual Operating Times

Operating\_time\_1 :=  $8760 \frac{\text{hr}}{\text{yr}}$

(note: 8760 hr per yr = 24 hr per day 365 days per year)

Operating\_time\_2 :=  $3679 \frac{\text{hr}}{\text{yr}}$

[note: 3679 hr per yr = (Boilers operating 5 months of the year or 42% of 8760 hr per yr)]

#### Given Criteria

MMBTU :=  $10^6 \text{ BTU}$

Boiler\_input :=  $50.2 \frac{\text{MMBTU}}{\text{hr}}$  (Boiler Heat Input)

EF<sub>NOx</sub> :=  $0.09 \frac{\text{lb}}{\text{MMBTU}}$  (Emission Factor)

(see Attachment B, Table I)

#### Calculations

Emission<sub>1</sub> := Boiler\_1\_number · Operating\_time\_1 · Boiler\_input · EF<sub>NOx</sub> (Emissions from 3 boilers operating at 8760 hours per year)

Emission<sub>1</sub> =  $59.367 \frac{\text{ton}}{\text{yr}}$

Emission<sub>2</sub> := Boiler\_2\_number · Operating\_time\_2 · Boiler\_input · EF<sub>NOx</sub> (Emissions from 3 boilers operating at 3679 hours per year)

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 5

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

$$\text{Emission}_2 = 24.933 \frac{\text{ton}}{\text{yr}}$$

$$\text{Emission}_{\text{total\_NOx}} = 84.299 \frac{\text{ton}}{\text{yr}}$$

$$\text{Emission}_{\text{total\_NOx}} := \text{Emission}_1 + \text{Emission}_2 \quad (\text{Total emissions from all boilers})$$

## 7.2 Determination of Boiler NOx Emission Concentration

Concentrations are expressed in dry standard cubic feet per minute. The volumetric fraction of water in the boiler exhaust is used to calculate the emission concentration on a dry basis.

$$\text{Vol\_Fraction}_{\text{water}} := .1446 \quad (\text{Assumed fraction of water in offgas stream, Reference 7})$$

$$\text{ppm}_v := \frac{1 \cdot \text{m}^3}{10^6 \cdot \text{m}^3} \quad (\text{Definition of ppm by volume})$$

Vendor Supplied Number Adjusted to 3% O<sub>2</sub> STP Converted to dry STP, Attachment B, Table 1.

$$\text{Boiler\_conc}_{\text{NOx\_Vendor\_3O2}} := 70 \text{ ppm}_v$$

$$\text{Boiler\_conc}_{\text{NOx\_ppm\_dry\_3O2}} := \frac{\text{Boiler\_conc}_{\text{NOx\_Vendor\_3O2}}}{(1 - \text{Vol\_Fraction}_{\text{water}})}$$

$$\text{Boiler\_conc}_{\text{NOx\_ppm\_dry\_3O2}} = 81.833 \text{ ppm}_v$$

(Boiler Concentration adjusted to 3% O<sub>2</sub> at dry standard conditions)

## 7.3 Determination of Annual Generator NOx Emission Rates

### Given Criteria

$$\text{Generator\_1\_number} := 1 \quad (\text{Number of Type I generators})$$

$$\text{Generator\_2\_number} := 2 \quad (\text{Number of Type II generators})$$

$$\text{Operating\_g\_time} := 164 \frac{\text{hr}}{\text{yr}} \quad \text{Efficiency} := .85$$

$$\text{kW} = 1.3405 \text{ ehp}$$

$$\text{Generator\_1\_size} := \frac{2500 \text{ kW}}{\text{Efficiency}} \quad \text{Generator\_1\_size} = 3942.6 \text{ ehp} \quad (\text{Type I generator size})$$

## CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 6

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

$$\text{Generator\_2\_size} := \frac{350\text{kW}}{\text{Efficiency}} \quad \text{Generator\_2\_size} = 5519.6\text{hp} \quad (\text{Type II generator size})$$

**Round up to 3950 and 5530 electric hp**

$$\text{Generator\_1\_size} := 3950\text{ehp}$$

$$\text{Generator\_2\_size} := 5530\text{ehp}$$

$$\text{EF\_gNO}_x := 1.65 \cdot 10^{-2} \frac{\text{lb}}{\text{hp} \cdot \text{hr}} \quad (\text{Emission Factor for Type I and II generators, see Attachment B, Table IIA})$$

$$\text{Emission}_{G1} := \text{Generator\_1\_number} \cdot \text{Operating\_g\_time} \cdot \text{Generator\_1\_size} \cdot \text{EF\_gNO}_x$$

$$\text{Emission}_{G2} := \text{Generator\_2\_number} \cdot \text{Operating\_g\_time} \cdot \text{Generator\_2\_size} \cdot \text{EF\_gNO}_x$$

$$\text{Emission\_g\_total\_NO}_x := \text{Emission}_{G1} + \text{Emission}_{G2}$$

$$\text{Emission}_{G1} = 5.347 \frac{\text{ton}}{\text{yr}} \quad \text{Emission}_{G2} = 14.97 \frac{\text{ton}}{\text{yr}}$$

$$\text{Emission\_g\_total\_NO}_x = 20.317 \frac{\text{ton}}{\text{yr}}$$

### 7.4 Determination of Generator NOx Emission Concentration

The following is the method used to calculate the NOx concentration in the generator exhaust corrected to dry standard conditions. The actual generator exhaust conditions are provided in Table A6.

#### Given Criteria (Standard Conditions)

$R_{\text{gas}}$  = Ideal gas law constant     $T_{\text{standard}}$  = Standard Temperature     $P$  = Standard Pressure

$MW_{\text{NO}_2}$  = Molecular Weight of  $\text{NO}_2$      $\text{ppm}_v$  = parts per million by volume conversion factor

$\text{Vol\_Fraction}_{\text{water}}$  = Volumetric Fraction of Water assumed to be 14.46%

$$R_{\text{gas}} := 0.082057 \frac{\text{liter} \cdot \text{atm}}{\text{K} \cdot \text{mole}} \quad T_{\text{standard}} := 293\text{K} \quad P := 1\text{atm}$$

$$MW_{\text{NO}_2} := 46 \frac{\text{gm}}{\text{mole}}$$

$$\text{Vol\_Fraction}_{\text{water}} := .1446 \quad (\text{Assumed fraction of water in offgas stream, Reference 7})$$

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

BY: J. Stan Hill

DATE: 6/17/03

SHEET REV: A

SHEET NO.: 7

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

The  $T_{\text{actual}}$  and flowrate were estimated based on extrapolation of data supplied by vendor 800-2,000 KW generators using regression analysis.

$$T_{\text{actual}} := 791.4\text{K} \quad T_{\text{correction}} := \frac{T_{\text{standard}}}{T_{\text{actual}}}$$

$$\text{Generator\_Exhaust\_flowrate1} := 18273.4 \frac{\text{ft}^3}{\text{min}}$$

## Calculation for NOx Concentration for Type 1 Generator

The NOx emission rate was calculated in pounds per hour by multiplying the generator size times the emission factor. The exhaust flow was corrected to dry conditions using the volumetric fraction of water in typical generator exhaust. The temperature correction was applied to the exhaust flow rate to correct to standard temperature.

$$\text{Generator\_Emission\_rate} := \text{Generator\_1\_size} \cdot \text{EF\_BNOx}$$

$$\text{Generator\_Emission\_rate} = 65.08 \frac{\text{lb}}{\text{hr}}$$

$$\text{Generator\_Exhaust\_flowrate\_standard1} := \text{Generator\_Exhaust\_flowrate1} \cdot T_{\text{correction}}$$

$$\text{Generator\_Exhaust\_flowrate\_standard1} = 11494 \frac{\text{m}^3}{\text{hr}}$$

$$\text{Generator\_Exhaust\_flowrate\_dry\_stp1} := \text{Generator\_Exhaust\_flowrate\_standard1} \cdot (1 - \text{Vol\_Fraction\_water})$$

$$\text{Generator\_Exhaust\_flowrate\_dry\_stp1} = 9832 \frac{\text{m}^3}{\text{hr}}$$

The generator NOx concentration was calculated by dividing the generator emission rate by the exhaust flow rate at dry standard conditions. The NOx concentration was then used to calculate ppm by volume at dry standard conditions.

$$\text{Generator\_conc\_NOx} := \frac{\text{Generator\_Emission\_rate}}{\text{Generator\_Exhaust\_flowrate\_dry\_stp1}}$$

$$\text{Generator\_conc\_NOx} = 3.008 \times 10^{-3} \frac{\text{mg}}{\text{m}^3}$$

$$\text{Generator\_conc\_NOx\_ppm} := \frac{\text{Generator\_conc\_NOx} \cdot R_{\text{gas}} \cdot T_{\text{standard}}}{\text{MW}_{\text{NO}_2} \cdot P}$$

$$\text{Generator\_conc\_NOx\_ppm} = 1572 \text{ppm}_v$$

## CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 8

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

### Correcting to 15% Oxygen:

After calculating the diesel generator exhaust concentration at dry standard conditions, the concentration was corrected to 15% oxygen. Correcting diesel generator exhaust pollutant concentrations to 15% oxygen is a common air permitting practice.

$$O2_{air} := 21\% \quad O2_{15\%} := 15\% \quad O2_{generator} := 11\%$$

$$O2_{correction\_g} := \frac{O2_{air} - O2_{15\%}}{O2_{air} - O2_{generator}}$$

$$O2_{correction\_g} = 0.6$$

$$Generator\_conc_{NOx\_ppm\_15\%O2} := Generator\_conc_{NOx\_ppm} \cdot O2_{correction\_g}$$

$$Generator\_conc_{NOx\_ppm\_15\%O2} = 943.3 ppm_v$$

### 7.5 Determination of Fire Water Pump NOx Emission Rate

The following is the method used to calculate the NOx concentration in the fire pump exhaust corrected to dry standard conditions. The actual fire pump exhaust conditions are provided in Table A8 and Attachment B, Table III.

#### Given Criteria

$$Pump_{number} := 2 \quad (\text{Number of fire water pumps})$$

$$Operating\_f_{time} := 110 \frac{hr}{yr} \quad (\text{Operating hours of one fire pump})$$

$$Pump\_size := 300 hp \quad (\text{Fire water pump size})$$

$$EF_{f_{NOx}} := 1.12 \cdot 10^{-2} \frac{lb}{hp \cdot hr} \quad (\text{Emission Factor})$$

(see Attachment B, Table III)

$$Vol\_Fraction\_water := .1446 \quad (\text{Assumed fraction of water in offgas stream, Reference 7})$$



## CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 9

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

### Calculation

The fire pump NO<sub>x</sub> emissions were calculated by multiplying the number of pumps by the operating time by the pump size by the emissions factor.

$$\text{Emission}_F := \text{Pump}_{\text{number}} \cdot \text{Operating\_time} \cdot \text{Pump}_{\text{size}} \cdot \text{EF}_{\text{NO}_x} \quad (\text{NO}_x \text{ emissions from fire water pumps})$$

$$\text{Emission}_F = 0.37 \frac{\text{ton}}{\text{yr}}$$

### 7.6 Determination of Fire Water Pump NO<sub>x</sub> Emission Concentration

#### Given Criteria

The fire pump exhaust data at actual conditions is given in Table A8 and Attachment B, Table III.

$$R_{\text{gas}} := 0.082057 \frac{\text{liter-atm}}{\text{K} \cdot \text{mole}} \quad (\text{Gas Law Constant})$$

$$\text{MW}_{\text{NO}_2} := 46 \frac{\text{gm}}{\text{mole}} \quad (\text{Molecular Weight of NO}_2)$$

$$P := 1 \text{ atm} \quad (\text{Standard Pressure})$$

$$T_{\text{standard}} := 293\text{K} \quad (\text{Standard Temperature})$$

(see reference 4)

$$T_{\text{actual}} := (443 + 273)\text{K}$$

$$T_{\text{actual}} = 716\text{K} \quad (\text{Exhaust gas actual temperature in Fahrenheit})$$

(see Attachment B, Table III)

$$T_{\text{standard}} := 293\text{K} \quad (\text{Standard Temperature})$$

(see reference 4)

$$T_{\text{actual}} := (443 + 273)\text{K}$$

$$T_{\text{actual}} = 716\text{K} \quad (\text{Exhaust gas actual temperature in Fahrenheit})$$

(see Attachment B, Table III)

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 10

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

$$T_{\text{correction}} := \frac{T_{\text{standard}}}{T_{\text{actual}}} \quad (\text{Gas flow rate temperature correction})$$

## Calculations

The NO<sub>x</sub> emission rate was calculated in pounds per hour by multiplying the generator size times the emission factor. The pump exhaust flow rate was corrected to dry standard conditions. The concentration of NO<sub>x</sub> in the pump exhaust was calculated at dry standard conditions.

$$\text{Emission\_F\_rate} := \text{Pump\_size} \cdot \text{EF\_f}_{\text{NO}_x} \quad (\text{Fire water pump emission rate})$$

$$\text{Emission\_F\_rate} = 3.36 \frac{\text{lb}}{\text{hr}}$$

$$\text{Pump\_Exhaust\_flowrate\_dry\_standard} := \text{Pump\_Exhaust\_flowrate} \cdot T_{\text{correction}} \cdot (1 - \text{Vol\_Fraction\_water})$$

$$\text{Pump\_Exhaust\_flowrate\_dry\_standard} = 976.547 \frac{\text{m}^3}{\text{hr}} \quad (\text{Gas flow rate with temperature and water correction})$$

$$\text{Pump\_conc\_NO}_x := \frac{\text{Emission\_F\_rate}}{\text{Pump\_Exhaust\_flowrate\_dry\_standard}}$$

$$\text{Pump\_conc\_NO}_x = 1.561 \times 10^3 \frac{\text{mg}}{\text{m}^3} \quad (\text{NO}_x \text{ concentration in generator exhaust})$$

$$\text{Pump\_conc\_NO}_x \text{ ppm} := \frac{\text{Pump\_conc\_NO}_x \cdot R_{\text{gas}} \cdot T_{\text{standard}}}{\text{MW}_{\text{NO}_2} \cdot P}$$

$$\text{Pump\_conc\_NO}_x \text{ ppm} = 815.7 \text{ ppm}_v \quad (\text{NO}_x \text{ concentration in generator exhaust converted to ppm})$$

## Correction of NO<sub>x</sub> concentration to 15% O<sub>2</sub>

After calculating the fire pump exhaust concentration at dry standard conditions, the concentration was corrected to 15% oxygen. Correcting diesel generator exhaust pollutant concentrations to 15% oxygen is a common air permitting practice.

## CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 11

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

$$O2\_air := 21\% \quad O2\_15\% := 15\% \quad O2\_pump := 11.3\%$$

$$O2\_correction\_f := \frac{O2\_air - O2\_15\%}{O2\_air - O2\_pump}$$

$$O2\_correction\_f = 0.619$$

$$Pump\_concNOx\_ppm\_15\%O2 := Pump\_concNOx\_ppm \cdot O2\_correction\_f$$

$$Pump\_concNOx\_ppm\_15\%O2 = 504.6 ppm_v$$

### 7.7 Emission Rate from Glass Former Facility

The glass former facility is a potential source of particulate emissions. The following calculation estimates the particulate matter emissions. Sodium carbonate is a glass former material used in the WTP process. The EPA has a published emissions factor for sodium carbonate storage, loading, and unloading, so this emissions factor was used to estimate WTP glass former facility emissions. The control efficiency for baghouses is assumed to be 99.9%.

#### Given Criteria

$$GlassFormer\_Throughput := 105200 \frac{lb}{day} \quad (\text{Glass former throughput lb/day})$$

$$GlassFormer\_Throughput = 52.6 \frac{ton}{day} \quad (\text{Glass former throughput ton/day})$$

$$EF\_PM := 5.2 \frac{lb}{ton} \quad (\text{Emission factor for particulate matter})$$

(see reference 1)

$$Controlled\_Efficiency := 0.999 \quad (\text{Particulate matter control equipment removal efficiency})$$

(see reference 1)

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 12

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

## Calculations

$$\text{Controlled\_Emission} := \text{GlassFormer\_Throughput} \cdot \text{EF\_PM} \cdot (1 - \text{Controlled\_Efficiency})$$

$$\text{Controlled\_Emission} = 99.901 \frac{\text{lb}}{\text{yr}} \quad (\text{Particulate matter emissions})$$

$$\text{Controlled\_Emission} = 0.05 \frac{\text{ton}}{\text{yr}} \quad (\text{Conversion to tons per year})$$

## 7.8 Determination of LAW Vitrification Process NOx Emission Concentration

$$R_{\text{gas}} := 0.082057 \frac{\text{liter} \cdot \text{atm}}{\text{K} \cdot \text{mole}} \quad (\text{Gas Law Constant})$$

$$T_{\text{standard}} := 293\text{K} \quad (\text{Standard Temperature})$$

$$P := 1\text{atm} \quad (\text{Standard Pressure})$$

$$\text{MW}_{\text{NO}_2} := (14.00674 + 2 \cdot 15.9994) \frac{\text{gm}}{\text{mole}} \quad (\text{Molecular Weight of NO}_2)$$

$$\text{MW}_{\text{NO}_2} = 46.006 \frac{\text{gm}}{\text{mole}}$$

$$\text{MW}_{\text{NO}} := (14.00674 + 15.9994) \frac{\text{gm}}{\text{mole}} \quad (\text{Molecular Weight of NO})$$

$$\text{MW}_{\text{NO}} = 30.006 \frac{\text{gm}}{\text{mole}}$$

$$T_{\text{actual}} := (174 + 459.67) \cdot \text{R} \quad (\text{Actual Temperature Converted to Rankine})$$

$$T_{\text{actual}} = 633.67\text{R}$$

$$T_{\text{actual}} = 352.03\text{K} \quad (\text{Actual Temperature Converted to Kelvin})$$

## CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 13

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

$$T_{\text{correction}} := \frac{T_{\text{standard}}}{T_{\text{actual}}}$$

[Temperature Correction Factor to Apply to Actual Flowrate to Convert to Standard Conditions (293 K)]

$$T_{\text{correction}} = 0.832$$

$$\text{Emission\_LV}_{\text{NO\_rate}} := 9.28 \cdot 10^{-1} \frac{\text{gm}}{\text{sec}}$$

(Mass Flowrate of NO in LAW Melter Offgas Stream)

$$\text{Emission\_LV}_{\text{NO}_2\text{\_rate}} := 1.30 \cdot 10^{-1} \frac{\text{gm}}{\text{sec}}$$

(Mass Flowrate of NO<sub>2</sub> in LAW Melter Offgas Stream)

$$\text{LV\_Exhaust}_{\text{flowrate}} := 5992 \frac{\text{ft}^3}{\text{min}}$$

(LAW Melter Offgas Volumetric Actual Flowrate, 24590-LAW-M4C-20-00001, Rev A.)

$$\text{LV\_Exhaust}_{\text{flowrate}} = 2.828 \frac{\text{m}^3}{\text{sec}}$$

(LAW Melter Offgas Volumetric Flowrate Converted to m<sup>3</sup>/sec)

$$\text{Relative\_Humidity} := .69$$

(Relative Humidity of LAW Melter Offgas System, 24590-LAW-M4C-20-00001, Rev A.)

### Calculations

Need to express final concentration in ppmv dry basis. Therefore need to adjust volume based on removal of water from the the vapor stream. From Perry's Handbook of Chemical Engineering (Reference 2), for T=170 F and 180F the vapor pressure of water under saturated conditions is 5.9926 and 7.5110 psi, respectively. Need to interpolate to find water vapor pressure at 174F.

$$P = 14.696 \text{ psi} \quad (\text{Standard Pressure in psi})$$

$$\text{VP}_{\text{water\_170}} := 5.9926 \text{ psi} \quad (\text{Vapor Pressure of Saturated Water at } T = 170 \text{ F})$$

$$\text{VP}_{\text{water\_180}} := 7.5110 \text{ psi} \quad (\text{Vapor Pressure of Saturated Water at } T = 180 \text{ F})$$

$$\text{VP}_{\text{water\_174}} := \text{VP}_{\text{water\_170}} + \frac{174 - 170}{180 - 170} (\text{VP}_{\text{water\_180}} - \text{VP}_{\text{water\_170}})$$

$$\text{VP}_{\text{water\_174}} = 6.6 \text{ psi}$$

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 14

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

$$VP_{\text{airstream}_174} := P - VP_{\text{water}_174} \cdot \text{Relative\_Humidity} \quad (\text{Actual vapor pressure of dry air stream subtracting out the water})$$

$$VP_{\text{airstream}_174} = 10.142 \text{ psi}$$

$$\text{Volume\_Reduction\_Fraction} := \frac{VP_{\text{airstream}_174}}{P} \quad (\text{Reduction in volumetric flowrate based on removing water})$$

$$\text{Volume\_Reduction\_Fraction} = 0.69$$

$$LV\_Exhaust_{\text{flowrate\_dry}} := LV\_Exhaust_{\text{flowrate}} \cdot \text{Volume\_Reduction\_Fraction}$$

$$LV\_Exhaust_{\text{flowrate\_dry}} = 4.135 \times 10^3 \frac{\text{ft}^3}{\text{min}} \quad (\text{LAW Melter Offgas flowrate on a dry basis})$$

$$LV\_Exhaust_{\text{flowrate\_dry\_STP}} := LV\_Exhaust_{\text{flowrate\_dry}} \cdot T_{\text{correction}} \quad (\text{LAW Melter Offgas Flowrate at standard temperature and pressure on a dry basis})$$

$$LV\_Exhaust_{\text{flowrate\_dry\_STP}} = 1.624 \frac{\text{m}^3}{\text{sec}}$$

$$LV\_conc_{\text{NOx\_ppm}} := \frac{\left( \frac{\text{Emission\_LV}_{\text{NO\_rate}}}{MW_{\text{NO}}} + \frac{\text{Emission\_LV}_{\text{NO2\_rate}}}{MW_{\text{NO2}}} \right) \cdot R_{\text{gas}} \cdot T_{\text{standard}}}{P \cdot LV\_Exhaust_{\text{flowrate\_dry\_STP}}}$$

$$LV\_conc_{\text{NOx\_ppm}} = 499.6 \text{ ppm}_v \quad (\text{NOx Concentration in units of ppm, dry basis})$$

## CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 15

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

### 7.9 Determination of Pretreatment Process & Vessel Vent NOx Emission Concentration

$$R_{\text{gas}} := 0.082057 \frac{\text{liter} \cdot \text{atm}}{\text{K} \cdot \text{mole}} \quad (\text{Gas Law Constant})$$

$$T_{\text{standard}} := 293\text{K} \quad (\text{Standard Temperature})$$

$$P := 1\text{atm} \quad (\text{Standard Pressure})$$

$$MW_{\text{NO}_2} := (14.00674 + 2 \cdot 15.9994) \frac{\text{gm}}{\text{mole}} \quad (\text{Molecular Weight of NO}_2)$$

$$MW_{\text{NO}_2} = 46.006 \frac{\text{gm}}{\text{mole}}$$

$$MW_{\text{NO}} := (14.00674 + 15.9994) \frac{\text{gm}}{\text{mole}} \quad (\text{Molecular Weight of NO})$$

$$MW_{\text{NO}} = 30.006 \frac{\text{gm}}{\text{mole}}$$

$$T_{\text{actual}} := (116 + 459.67) \cdot R \quad (\text{Actual Temperature, 116F, Converted to Rankine, 24590-PTF-MAC-PVV-00001})$$

$$T_{\text{actual}} = 575.67\text{R}$$

$$T_{\text{actual}} = 319.817\text{K} \quad (\text{Actual Temperature Converted to Kelvin})$$

$$T_{\text{correction}} := \frac{T_{\text{standard}}}{T_{\text{actual}}} \quad [\text{Temperature Correction Factor to Apply to Actual Flowrate to Convert to Standard Conditions (293 K)}]$$

$$T_{\text{correction}} = 0.916$$

$$\text{Emission\_PVP12\_NO\_rate} := 2.24 \cdot 10^{-26} \frac{\text{gm}}{\text{sec}} \quad (\text{Mass Flowrate of NO in Pretreatment Offgas Stream})$$

$$\text{Emission\_PVP12\_NO}_2\text{\_rate} := 5.25 \cdot 10^{-33} \frac{\text{gm}}{\text{sec}} \quad (\text{Mass Flowrate of NO}_2 \text{ in Pretreatment Offgas Stream})$$

$$\text{Radiolytic\_NO}_2\text{\_rate} := (95.6714) \cdot \frac{\text{lb}}{\text{yr}} \cdot (1 - .33) \quad (\text{Radiolytic NO}_x \text{ emission with 33\% abatement, annualized})$$

(Engineering Calculation 24590-PTF-MKC-PVP-00001, Rev. B)

## CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

BY: J. Stan Hill

DATE: 6/17/03

SHEET REV: A

SHEET NO.: 16

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

$$\text{Radiolytic}_{\text{NO}_2\_rate} = 1.29 \times 10^{-2} \frac{\text{gm}}{\text{sec}} \quad (\text{Radiolytic NOx emission in grams per second})$$

$$\text{Total\_PVP12}_{\text{NO}_2\_rate} := \text{Emission\_PVP12}_{\text{NO}_2\_rate} + \text{Radiolytic}_{\text{NO}_2\_rate}$$

$$\text{Total\_PVP12}_{\text{NO}_2\_rate} = 0.013 \frac{\text{gm}}{\text{sec}}$$

$$\text{PVP12\_Exhaust}_{flowrate} := 2735 \frac{\text{ft}^3}{\text{min}} \quad (\text{Pretreatment Offgas Volumetric Flowrate, 24590-PTF-M5-V17T-00021001})$$

$$\text{PVP12\_Exhaust}_{flowrate} = 1.291 \frac{\text{m}^3}{\text{sec}} \quad (\text{Pretreatment Offgas Volumetric Flowrate Converted to m}^3/\text{sec})$$

$$\text{Relative\_Humidity} := .70 \quad (\text{Relative Humidity of Pretreatment Offgas System, 24590-PTF-MAC-PVV-00001})$$

### Calculations

Need to express final concentration in ppmv dry basis. Therefore need to adjust volume based on removal of water from the the vapor stream. From Perry's Handbook of Chemical Engineering (Reference 2), for T=110 F and 120F the vapor pressure of water under saturated conditions is 1.2750 and 1.6927 psi, respectively.

Need to interpolate to find water vapor pressure at 116F.

$$P = 14.696\text{psi} \quad (\text{Standard Pressure in psi})$$

$$\text{VP}_{\text{water\_110}} := 1.2750\text{psi} \quad (\text{Vapor Pressure of Saturated Water at T = 110 F})$$

$$\text{VP}_{\text{water\_120}} := 1.6927\text{psi} \quad (\text{Vapor Pressure of Saturated Water at T = 120 F})$$

$$\text{VP}_{\text{water\_116}} := \text{VP}_{\text{water\_110}} + \frac{116 - 110}{120 - 110} (\text{VP}_{\text{water\_120}} - \text{VP}_{\text{water\_110}})$$

$$\text{VP}_{\text{water\_116}} = 1.526\text{psi} \quad (\text{Vapor Pressure of Saturated Water at T = 116 F})$$

$$\text{VP}_{\text{airstream\_116}} := P - \text{VP}_{\text{water\_116}} \cdot \text{Relative\_Humidity} \quad (\text{Actual vapor pressure of dry air stream subtracting out the water})$$

$$\text{VP}_{\text{airstream\_116}} = 13.628\text{psi}$$



# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 17

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

$$\text{Volume\_Reduction\_Fraction} := \frac{VP_{\text{airstream\_116}}}{P} \quad (\text{Reduction in volumetric flowrate based on removing water})$$

$$\text{Volume\_Reduction\_Fraction} = 0.927$$

$$\text{PVP12\_Exhaust\_flowrate\_dry} := \text{PVP12\_Exhaust\_flowrate} \cdot \text{Volume\_Reduction\_Fraction}$$

$$\text{PVP12\_Exhaust\_flowrate\_dry} = 2.536 \times 10^3 \frac{\text{ft}^3}{\text{min}} \quad (\text{Pretreatment Offgas Flowrate on a dry basis})$$

$$\text{PVP12\_Exhaust\_flowrate\_dry\_STP} := \text{PVP12\_Exhaust\_flowrate\_dry} \cdot T_{\text{correction}}$$

$$\text{PVP12\_Exhaust\_flowrate\_dry\_STP} = 2.324 \times 10^3 \frac{\text{ft}^3}{\text{min}} \quad (\text{Pretreatment Offgas Flowrate at standard temperature and pressure on a dry basis})$$

$$\text{PVP12\_Exhaust\_flowrate\_dry\_STP} = 1.097 \frac{\text{m}^3}{\text{sec}}$$

$$\text{PVP12\_conc\_NOx\_ppm} := \frac{\left( \frac{\text{Emission\_PVP12\_NO\_rate}}{MW_{\text{NO}}} + \frac{\text{Total\_PVP12\_NO2\_rate}}{MW_{\text{NO2}}} \right) \cdot R_{\text{gas}} \cdot T_{\text{standard}}}{P \cdot \text{PVP12\_Exhaust\_flowrate\_dry\_STP}}$$

$$\text{PVP12\_conc\_NOx\_ppm} = 6.1 \text{ ppm}_v \quad (\text{NOx Concentration in units of ppm, dry basis})$$

## CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 18

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

## 8 Results and Conclusion

These calculations provide the basis for determining PSD regulated constituent emissions at WTP. The results are provided in Attachment A.

## 9 References

1. EPA. 1998. *Compilation of Air Pollutant Emissions Factors AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources*, 1998. Clearinghouse for Inventories and Emissions Factors, Office of Air Quality Planning and Standards. Research Triangle Park, North Carolina, USA.
2. Perry's Handbook of Chemical Engineering, 6th edition, Perry & Green, McGraw Hill.
3. Prevention of Significant Deterioration (PSD) Permit Application (24590-WTP-RPT-ENV-01-007, rev.1)
4. 40 CFR 60, Appendix A, Method 2.
5. 40 CFR 60, Appendix A, Method 20.
6. Vender literature: Boiler Emission Reference Guide, 2nd edition, Cleaver Brooks.
7. Marks' Standard Handbook for Mechanical Engineers, 9th Edition, Avallon & Baumeister, McGraw Hill.

## 10 Attachments

Attachment A: Emission Rates and Concentrations of PSD Regulated Constituents.

Attachment B: Vendor Quotes

## CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 19

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

### Attachment A

## CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 20

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

Table A1: Emission Rates (ton/yr) Summary

Criteria Pollutant	Total Boiler + Generator + Fire water Pump + Glass Formers (ton/yr)	PT process (ton/yr)	LAW Vit Process (ton/yr)	HLW Vit process (ton/yr)	WTP Total (ton/yr)	PSD Significance Limit (ton/yr)
CO	68.0	7.94E-21	2.20E+00	3.65E-01	70.59	100
NO <sub>x</sub>	105.0	4.49E-01	3.67E+01	8.50E+00	150.68	40
SO <sub>2</sub>	3.0	1.09E-21	3.68E+00	4.84E+00	11.47	40
PM	19.5	2.04	1.58	1.18	24.25	15
VOCs	28.9	3.84	0.47	0.38	33.60	40
Pb	1.36E-02	1.03E-09	2.65E-09	1.99E-11	0.01	6.00E-01
Fluorides	0.00	1.25E-08	3.76E-07	8.86E-13	3.88E-07	3
H <sub>2</sub> SO <sub>4</sub> Mist	0.00	1.86E-08	1.79E-11	1.57E-14	1.87E-08	7
H <sub>2</sub> S	0.00	0.00E+00	0.00E+00	0.00E+00	0.00	10
Total Reduced Sulfur	0.00	3.76E-14	3.68E-01	4.84E-01	0.85	10
Ozone-Depleting Sub.	0.00	0.00	0.00	0.00	0.00	100

Note: 1 ton = 2000 lb.

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 21

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

Table A2: Emission Concentrations (ppmv) Summary

## Criteria Pollutant Emission Concentrations from BOF Facilities

Criteria Pollutant	Boiler - corrected to 3% O2 (ppmv)	Generator - Type I (ppmv)	Generator Type I - corrected to 15% O2 (ppmv)	Generator - Type II (ppmv)	Generator Type II - corrected to 15% O2 (ppmv)	Fire Water Pump (ppmv)	Fire Water Pump - corrected to 15% O2 (ppmv)
NOx	82	1,572	943	2,057	1,234	819	507
PM	N/A	N/A	N/A	N/A	N/A	N/A	N/A

## Criteria Pollutant Emission Concentrations from Pretreatment, LAW Vitrification, and HLW Vitrification Plants

Criteria Pollutant	LAW Vit Process (ppmv)	HLW Vit process (ppmv)
NOx	477	352
PM	NA	NA

## CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 22

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

Table A3: Emission Rates (ton/yr) for Boilers

Criteria Pollutant	Number of Boilers	Op. Hour/yr/boiler <sup>2</sup>	Number of Boilers	Op. Hour/yr/boiler	Total Operating Hours (hr/yr)	Boiler Input (MMBtu/hr) <sup>3</sup>	Emission Factor (lb/1000 gal)	Emission Factor <sup>1</sup> (lb/MMBtu)	Conversion Factor (lb to tons) <sup>5</sup>	Annual Boiler Emissions (tons/yr)
CO	3	8760	3	3679	37318	50.2	NA	0.070	0.0005	65.6
NOx	3	8760	3	3679	37318	50.2	NA	0.09	0.0005	84.3
SO <sub>2</sub>	3	8760	3	3679	37318	50.2	NA	0.003	0.0005	2.9
PM <sup>4</sup>	3	8760	3	3679	37318	50.2	NA	0.020	0.0005	18.7
VOCs	3	8760	3	3679	37318	50.2	NA	0.030	0.0005	28.1
Pb	3	8760	3	3679	37318	50.2	NA	9.00E-06	0.0005	8.43E-03

## Notes:

1. All emission factors are based on vendor quotes with the exception of lead. The emission factor for SO<sub>2</sub> is based on a S content of 0.003% by weight in fuel oil. The emission factor for lead is based on the EPA AP-42 factor. The conversion from MMBtu to gallon is assumed to be 140MMBtu = 1000 gal.
2. 8760 hours per year per boiler was allocated to 3 boilers and 3679 hours per year per boiler was allocated to the remaining 3 boilers.
3. The boiler heat input is assumed to be 50.2 million British thermal unit (Btu) per hour.
4. All particulate matter is assumed to be PM<sub>10</sub>.
5. The conversion from ton to lb is 1 ton = 2000 lb.

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 23

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1.

Table A4: Emission Concentrations (ppmv) for a Single Boiler

Criteria Pollutant	boiler heat input <sup>1</sup>	emission factor <sup>2</sup>	boiler hourly emissions	Boiler - Corrected to 3% O <sub>2</sub> dry STP <sup>3,4</sup>
	MMBtu/hr	lb/MMBtu	lb/hr	ppmv
NO <sub>x</sub> <sup>4</sup>	50.2	0.09	4.52	82
PM	50.2	0.020	1.00	N/A

## Boiler Exhaust Data

Boiler Exhaust Flowrate	10,065	SCFM
	14,628	dsm <sup>3</sup> /hr
Water Content of Offgas <sup>5</sup>	14.46%	F

## Notes:

1. See Table A3 for assumptions related to emission factors.
2. A conversion factor of 140 MMBTU (million BTU) per 1,000 gallons of fuel is used from EPA AP-42.
3. The Boiler exhaust flow rate is assumed to be 10,065 standard cubic feet per minute (SCFM) with a exhaust temperature of 425 °F (see below).
4. Based on vendor supplied data adjusted for 3% oxygen at standard temperature and pressure on a dry basis, Appendix B Table 1.
5. Marks' Standard Handbook for Mechanical Engineers, 9th Edition, Avallone & Baumeister, McGraw Hill.

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 24

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

Table A5: Emission Rates (ton/yr) for Generators

Criteria Pollutant	Number of Type I gen. <sup>1</sup>	Op. Hour per yr per gen. <sup>3</sup>	Total Op. Hours (hr/yr)	Type I Gen. size (hp/gen.) <sup>2</sup>	Number of Type II gen. <sup>1</sup>	Op. Hour per year per gen. <sup>3</sup>	Total Op. Hours (hr/yr)	Type II Gen. Size (hp/gen.) <sup>2</sup>	Emission Factor (gm/hp-hr)	Emission Factor (lb/hp-hr)	Conversion Factor (lb to tons) <sup>7</sup>	Annual Gen. Emissions (tons/yr)
NOx <sup>4</sup>	1	164	164	3950	2	164	328	5530	7.5	1.65E-02	0.0005	20.4
SO <sub>2</sub> (S content @30 ppm <sub>w</sub> ) <sup>4</sup>	1	164	164	3950	2	164	328	5530	NA	2.43E-05	0.0005	0.03
CO <sup>4</sup>	1	164	164	3950	2	164	328	5530	0.9	1.98E-03	0.0005	2.4
PM <sup>4,6</sup>	1	164	164	3950	2	164	328	5530	0.25	5.51E-04	0.0005	0.7
VOCs <sup>4</sup>	1	164	164	3950	2	164	328	5530	0.3	6.61E-04	0.0005	0.8
Pb <sup>3</sup>	1	164	164	3950	2	164	328	5530	NA	3.85E-06	0.0005	4.7E-03

notes:

1. There will be two types of generators: Type I is assumed to be 3950 horse power (hp) [or 2500 kilo watt (KW)] and Type II is assumed to be 5530 hp (or 3500 KW).
2. The conversion factor from KW to hp is:  $hp = 1 \text{ KW} * 1.341 / (\text{generator efficiency of } 85\%) = 1 * \text{KW} * 1.58$ .
3. Each diesel generator will be tested every 2 weeks for 6 hours with a 8 hour per year run in the event of loss of power.
4. The emission factors for NOx, CO, PM and VOCs are based on vendor quotes for 2500 KW generators.  
The emission factors for SO<sub>2</sub> is based on EPA AP-42 for S content of 0.05% by weight: emission factor for large stationary diesel engines, SCC 2-02-004-01 (AP-42 Section 3.4, Table 3.4-1.A with conversion factor of 140 MMBtu per 1000 gallons of fuel oil is used). The EPA emission factor for SO<sub>2</sub> was corrected for 0.05% by weight of S by multiplying the EPA emission factor by 0.05.
5. The emission factor for lead is calculated from California Air Resources Board (CARB), 1991: Identification of Particulate Matter Species Profiles, ARB Speciation Manual, Second Edition, Volume 2 of 2. The emission factor for lead is determined using the 0.0055 time the EPA AP-42 PM emission factor. (note: The PM emission factor is for large stationary diesel engines, SCC 2-02-004-01: AP-42 Section 3.4, Table 3.4-1).
6. All particulate matter is assumed to be PM10.
7. The conversion from ton to lb is 1 ton = 2000 lb.



# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 25

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

Used Excel Linear Regression Tool on Vendor Data (Attachment B) to Provide Equation to Extrapolate Exhaust Stack Temperature and Flowrate for Generators of size 2,500 hp and 3,500 hp.

Generator Size (KW)	Generator Size <sup>2</sup> (KW <sup>2</sup> )	Exhaust Stack Temp (F)	Generator Size (KW)	Exhaust Gas Flowrate (CFM)
2,000	4,000,000	842	2,000	15,204
1,800	3,240,000	791	1,800	13,880
1,600	2,560,000	757	1,600	12,705
1,500	2,250,000	744	1,500	12,030
1,400	1,960,000	732	1,400	11,356
1,200	1,440,000	712	1,200	10,102
1,000	1,000,000	693	1,000	8,902
800	640,000	672	800	7,747

For Temperature Obtained the Following Summary Output

## SUMMARY OUTPUT

<i>Regression Statistics</i>	
Multiple R	0.997005799
R Square	0.994020562
Adjusted R Square	0.991628787
Standard Error	5.002379178
Observations	8

<i>Coefficients</i>	
Intercept	683.3232415
Generator Size (KW)	-0.065707336
Generator Size <sup>2</sup> (KW <sup>2</sup> )	7.13228E-05

$$\text{Temperature} = 7.13 \times 10^{-5} \times \text{KW}^2 - .0656 \times \text{KW} + 683$$

## CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 26

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

For Flowrate Obtained the Following Summary Output

<i>Regression Statistics</i>	
Multiple R	0.999788818
R Square	0.999577681
Adjusted R Square	0.999507294
Standard Error	55.60395935
Observations	8

<i>Coefficients</i>	
Intercept	2681.09856
Generator Size (KW)	6.236921373

$$\text{Flowrate (CFM)} = 6.24 * \text{KW} + 2681$$

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 27

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

**Table A6: Emission Concentrations (ppmv) for a Single Generator**

Type I Generator							
Criteria Pollutant	Op. Hour/yr/generator	Type I Generator Size	Emission Factor <sup>1</sup>	hourly emissions	exhaust concentration	exhaust concentration (standard conditions) <sup>2</sup>	exhaust concentration (standard conditions, corrected to 15% O <sub>2</sub> )
	hr	(hp/generator)	(lb/hp-hr)	lb/hr	mg/m <sup>3</sup>	ppm	ppm
NO <sub>x</sub> (3)	164	3950	1.65E-02	65.18	3.01E+03	1572	943
PM	164	3950	5.51E-04	2.18	1.00E+02	N/A	N/A
Type II Generator							
Criteria Pollutant	Op. Hour/yr/generator	Type II Generator Size	Emission Factor <sup>1</sup>	hourly emissions	exhaust concentration	exhaust concentration (standard conditions)	exhaust concentration (standard conditions, corrected to 15% O <sub>2</sub> )
	hr	(hp/generator)	(lb/hp-hr)	lb/hr	mg/m <sup>3</sup>	ppm	ppm
NO <sub>x</sub>	164	5530	1.65E-02	91.25	3.95E+03	2067	1240
PM	164	5530	5.51E-04	3.05	1.32E+02	N/A	N/A

Estimated 2500 KW (or ~3950 hp) Generators Exhaust Data:

Estimated 3500 KW (or ~5530 hp) Generators Exhaust Data:

Single Generator Exhaust Flowrate	18,273.4	CFM	Single Generator Exhaust Flowrate	24,510.3	CFM
	31,047	m <sup>3</sup> /hr		41,644	m <sup>3</sup> /hr
	26,557	m <sup>3</sup> /hr (dry)		35,622	m <sup>3</sup> /hr (dry)
	9832	m <sup>3</sup> /hr (dry standard)		10514	m <sup>3</sup> /hr (dry standard)
Exhaust Temperature	964.8	F	Exhaust Temperature	1,327.1	F
	791.4	K		992.7	K
Temperature at Standard Conditions	293	K	Temperature at Standard Conditions	293	K
Correction Factor for Temperature	0.370		Correction Factor for Temperature	0.295	
Assumed Vol % Water <sup>4</sup>	14.46%		Assumed Vol % Water <sup>4</sup>	14.46%	

**Notes:**

1. See Table A5 footnotes for assumptions on emission factors.
2. The oxygen content in the exhaust is assumed to be 11%.
3. The NO<sub>x</sub> concentration in parts per million (ppm<sub>v</sub>) is determined based on nitrogen oxide (NO<sub>2</sub>).
4. Table 9.6.17, "Marks Standard Handbook for Mechanical Engineers", 9th Edition, Avaloone & Baumeister, McGraw Hill.

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 28

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

**Table A7: Emission Rates (ton/yr) from Diesel Driven Fire Water Pumps**

Criteria Pollutant	# of fire pump	Op.hour/yr/pump	Total Operating Hours (hr/yr)	Fire water pump size (hp/pump)	Emission Factor (gm/hp-hr)	Emission Factor (lb/hp-hr)	Conversion Factor (lb to tons)	Annual Boiler Emissions (tons/yr)
CO	2	110	220	300	0.22	4.85E-04	0.0005	<b>0.02</b>
NOx	2	110	220	300	5.1	1.12E-02	0.0005	<b>0.4</b>
SO <sub>2</sub> ( S content @30 ppm)	2	110	220	300	0.0084	1.85E-05	0.0005	<b>0.0006</b>
PM	2	110	220	300	0.07	1.54E-04	0.0005	<b>0.01</b>
VOCs	2	110	220	300	0.07	1.54E-04	0.0005	<b>0.01</b>
Pb	2	110	220	300	NA	1.21E-05	0.0005	<b>0.0004</b>
Notes:								

1. The operating hours were determined based on a 1 hour weekly testing run, a 3-hour annual testing, and other miscellaneous uses.
2. The emission factors for NOx, SO<sub>2</sub>, CO, VOC and PM are based on vendor quotes. The emission factor from the vendor for SO<sub>2</sub> is based on fuel containing a S content of 0.05% by weight (Appendix B, Table III). Adjusted to 0.003% for ultra low sulfur fuel by multiply by a ratio of 0.00003/0.0005.
3. The emission factor is calculated from California Air Resources Board (CARB ), 1991: Identification of Particulate Matter Species Profiles, ARB Speciation Manual, Second Edition, Volume 2 of 2. The emission factor for lead is determined using the 0.0055 time the EPA AP-42 PM emission factor. (Note: The PM emission factor is for large stationary diesel engines, SCC 2-02-004-01: AP-42 Section 3.4, Table 3.4-1).
4. Conversion from ton to pound is 1 ton = 2000 lb.

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 29

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

**Table A8: Emission Concentration (ppm<sub>v</sub>) from a Single Diesel Driven Fire Water Pump**

Criteria Pollutant	Op. Hour/yr/pump	Fire water pump size	Emission Factor <sup>1</sup>	hourly emissions	exhaust concentration <sup>2</sup>	exhaust concentration (dry standard conditions) <sup>3</sup>	exhaust concentration (standard conditions, corrected to 15% O <sub>2</sub> )
	hr	(hp/pump)	(lb/hp-hr)	lb/hr	mg/m <sup>3</sup>	ppm <sub>v</sub>	ppm <sub>v</sub>
NO <sub>x</sub>	110	300	1.12E-02	3.37	1.57E+03	819	507
PM	110	300	1.54E-04	0.05	2.15E+01	N/A	N/A

300 hp Fire Water Pump Exhaust Data:		
Single Fire Water Pump Exhaust Flowrate	1,642	CFM
	2,790	m <sup>3</sup> /hr
	977	m <sup>3</sup> /hr (dry standard)
Exhaust Temperature	829	F
	716.0	K
Temperature at Standard Conditions	293	K
O <sub>2</sub> content	11.30	%
Assumed Vol % Water <sup>4</sup>	14.46	%

## Notes:

1. See Table A7 for assumptions related to the emission factors.
2. The NO<sub>x</sub> concentration in parts per million (ppm<sub>v</sub>) is determined based on nitrogen oxide (NO<sub>2</sub>).
3. The oxygen content in the exhaust is assumed to be 11.3%.
4. Table 9.6.17, "Marks Standard Handbook for Mechanical Engineers", 9th Edition, Avaloone & Baumeister, McGraw Hill.

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 30

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

**Table A9: Emission Rates (Ton/yr) from Glass Former Storage Building**

Glass Former	Minimum Consumption (lb/day)	Maximum Consumption (lb/day)
Aluminum Silicate	1,000	7,500
Boric Acid	5,400	16,200
Calcium Silicate	1,400	10,000
Ferric Oxide	1,600	4,400
Lithium Carbonate	1,200	11,700
Magnesium Silicate	1,100	4,200
Silica	14,900	34,100
Sodium Carbonate	0	1,200
Sucrose	200	5,100
Titanium Dioxide	0	1,400
Zinc Oxide	1,100	2,400
Zirconium Silicate	0	3,300
Borax	1,000	3,700
Total material processed (lb/day)	28,900	105,200
Total material processed (ton/day)	14.5	52.6
Total material processed (ton/yr)	5,274	19,199
Particulate emission factor for PM <sub>10</sub>	5.2 lb/ton	5.2 lb/ton
Uncontrolled emissions of PM <sub>10</sub> (lb/yr)	27,426	99,835
Controlled emissions (99.9%) of PM <sub>10</sub> (lb/yr)	27.4	99.8
Controlled emissions (99.9%) of PM <sub>10</sub> (ton/yr)	0.01	0.05

**Note:**

Particulate (PM<sub>10</sub>) emission factor and controlled emission efficiency of is determined based on EPA AP-42, Section 8.12, for storage, loading, and unloading of sodium carbonate, a glass former.

## CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 31

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

Table A10: Summary on Emission Rates (ton/yr) of Criteria Pollutants from Pretreatment, LAW, and HLW Vitrification Processes

Descriptions	Data Source / Table or Stream #	NOx Emission (ton/yr)	PM Emission (ton/yr)	CO Emission (ton/yr)	SO2 Emission (ton/yr)	VOC Emission (ton/yr)	Pb Emission (ton/yr)
PT-HVAC	See Note 1/Tables 15-7, 15-8, 15-9	0.00	<0.1	0.00	0.00	0.00	0.00
Process vessel vent & PJV exhausts	See Note 2/ Stream #PVP12, #PJV1 also includes 0.45 tons/year of abated NOx associated with radiolytic decay	4.49E-01	2.04E+00	7.94E-21	1.09E-21	3.84E+00	1.03E-09
LV-HVAC	See Note 1/Tables 15-10, 15-11, 15-12, 15-13	0.00	<0.1	0.00	0.00	0.00	0.00
LV melter offgas & Process vessel vent	See Note 2/Stream #LVP26	3.67E+01	1.58E+00	2.20E+00	3.68E+00	4.46E-01	2.65E-09
HV-HVAC	See Note 1/Tables 15-14, 15-15, 15-16, 15-17	0.00	<0.1	0.00	0.00	0.00	0.00
HV: offgases from melters & process vessel vents plus PJV exhausts	See Note 2/Streams #IOP33, #PJV34	8.50E+00	1.18E+00	3.65E-01	4.84E+00	3.76E-01	1.99E-11

## Notes:

1. Radioactive Air Emissions Notice of Construction Application for the River Protection Project - Waste Treatment Plant (24590-WTP-RPT-ENV-01-008, Rev. 1).
2. Emissions Maximum Case Runs with Updated Parameters (24590-WTP-MRQ-PT-03-002, Rev. 0).
3. Based on process knowledge, trace amount of NOx emission is expected.
4. Radioactive particulate is the primary source of particulate emissions for the HVAC systems. The total radioactive particulate is several order of magnitude lower than the total particulate emissions from the vitrification processes.

# CALCULATION SHEET

BY: J. Stan Hill

DATE: 6/17/03

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 32

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

**Table A11: Summary on Emission Rates (ton/yr) of Non-Criteria Pollutants from Pretreatment, LAW and HLW Vitrification Processes**

Descriptions	Data Source / Table or Stream #	Fluorides Emission (ton/yr)	H <sub>2</sub> SO <sub>4</sub> Emission (ton/yr)	H <sub>2</sub> S Emission (ton/yr)	Total Reduced Sulfur Emission (ton/yr)	Ozone-Depleting Sub. Emission (ton/yr)
PT-HVAC <sup>1</sup>	Tables 15-7, 15-8, 15-9 <sup>1</sup>	0.00	<0.1	0	0.00E+00	0
Process vessel vent & PJV exhausts	Stream #PVP12, #PJV1 <sup>2</sup>	1.25E-08	1.86E-08	0	3.76E-14	0
LV-HVAC <sup>3</sup>	Tables 15-10, 15-11, 15-12, 15-13 <sup>1</sup>	0.00	<0.1	0	0.00E+00	0
LV melter offgas & Process vessel vent	Stream #LVP26 <sup>2</sup>	3.76E-07	1.79E-11	0	3.68E-01	0
HV-HVAC <sup>3</sup>	Tables 15-14, 15-15, 15-16, 15-17 <sup>1</sup>	0.00	<0.1	0	0.00E+00	0
HV: offgases from melters & process vessel vents plus PJV exhausts	Streams #HOP33, #PJV34 <sup>2</sup>	8.86E-13	1.57E-14	0	4.84E-01	0

**Notes:**

1. Radioactive Air Emissions Notice of Construction Application for the River Protection Project - Waste Treatment Plant (24590-WTP-RPT-ENV-01-008, Rev. 1).
2. Emissions Maximum Case Runs with Updated Parameters (24590-WTP-MRQ-PT-03-002, Rev. 0).
3. Radioactive particulate is the primary source of particulate emissions for the HVAC systems. The total rad particulate is several order of magnitude lower than the total particulate emissions from the vitrification processes. Therefore, insignificant levels of particulate emissions are expected from the Heating, Ventilation, and Air Conditioning (HVAC) systems. Other PSD regulated pollutants are not expected.



# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 33

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

Table A12: Emission Concentration (ppmv) from Pretreatment, LAW, and HLW Vitrification Processes

Criteria Pollutant	Pretreatment Stack <sup>1</sup> (gm/sec)	Concentration (gm/m <sup>3</sup> )	Concentration (ppmv)
NOx	1.35E-02	1.23E-02	6.15E+00
PM	5.87E-02	5.35E-02	NA

Criteria Pollutant	LAW Vitrification Stack <sup>1</sup> (gm/sec)	Concentration (gm/m <sup>3</sup> )	Concentration (ppmv)
NOx	1.06E+00	6.21E-01	4.77E+02
PM	4.54E-02	2.67E-02	NA

Criteria Pollutant	HLW Vitrification Stack <sup>1</sup> (gm/sec)	Concentration (gm/m <sup>3</sup> )	Concentration (ppmv)
NOx	2.45E-01	4.59E-01	3.52E+02
PM	1.70E-02	3.17E-02	NA

Facility	Flow rates <sup>3</sup> (CFM -STP Dry Basis)	Flow rates (m <sup>3</sup> /sec, STP Dry Basis)
PT	2,324	1.10
LV	3,608	1.70
HV	1,131	0.53

## Notes:

1. Data source: 24590WTP-MRQ-PT-03-002, Rev. 0: Emissions Maximum Case Runs with Updated Parameters. 24590-PTF-MKC-PVP-00001, Rev. B: Pretreatment emissions includes 0.45 tons/year of abated NOx associated with radiolytic decay. Assumes NOx abatement efficiency of 30%.
2. The oxygen content from the exhaust is assumed to be 20%.
3. Data sources: For pretreatment: 24590-PTF-M5-V17T-002100; for LAW vitrification plant: 24590-LAW-M4C-20-00001, Rev. A; for HLW vitrification plant: 24590-HLW-M4C-30-00001, Rev. A.

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 34

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

Attachment B: Vendor Quotes:

## I. Emission data for boilers:

### Cleaver-Brooks Boiler Estimated Exhaust/Emission Performance Data

#### Boiler Summary Data

Boiler Model:	CBL200-1200-200ST	Steam/Hot Water:	Steam
Fuel:	No. 2 Oil	Steam Pressure, psig:	135
Input, Btu/hr:	50,212,500		

	Firing Rate			
	25%	50%	75%	100%
Horsepower	300	600	900	1200
Btu/hr	12,553,125	25,106,250	37,659,375	50,212,500

#### Emission Performance

CO	ppm	90	90	90	90
	lb/MMBtu	0.070	0.070	0.070	0.070
	lb/hr	0.88	1.76	2.64	3.51
	tpy	3.85	7.70	11.55	15.40
NOx	ppm	70	70	70	70
	lb/MMBtu	0.09	0.09	0.09	0.09
	lb/hr	1.17	2.34	3.51	4.68
	tpy	5.1	10.3	15.4	20.5
SOx	ppm	28	28	28	28
	lb/MMBtu	0.052	0.052	0.052	0.052
	lb/hr	0.65	1.29	1.94	2.59
	tpy	2.8	5.7	8.5	11.3
HC/VOCs	ppm	60	60	60	60
	lb/MMBtu	0.03	0.03	0.03	0.03
	lb/hr	0.377	0.753	1.130	1.506
	tpy	1.65	3.30	4.95	6.60
PM	ppm	N/A	N/A	N/A	N/A
	lb/MMBtu	0.020	0.020	0.020	0.020
	lb/hr	0.250	0.499	0.749	0.999
	tpy	1.09	2.19	3.28	4.37

#### Exhaust Data

Temperature, F		385	405	415	425
Flow	ACFM	4,738	8,213	12,462	16,806
	SCFM	2,972	5,032	7,549	10,065
	lb/hr	13,366	22,635	33,952	45,259
Velocity	ft/sec	11.17	19.37	29.38	39.53
	ft/min	670.3	1161.9	1763.1	2377.6

Notes: All ppm levels are corrected to 3% oxygen  
 No. 2 Oil emission levels are based on the following fuel constituent levels:  
 Ash Content 0.01 %, by weight  
 Fuel-bound Nitrogen Content 0.02 %, by weight  
 Sulfur Content 0.05 %, by weight  
 If any of the actual fuel constituent levels are different than indicated above, the emission levels will change.

## CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 35

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

### IIA. Emission data for a 2500 kW Generator:

	50%	75%	100% of rating
NO <sub>x</sub>	6	7	7.5
CO	1	0.9	0.9
THC	0.4	0.3	0.3
PM	0.3	0.28	0.25

All data is in gm / hp-h.

THC= Total Hydrocarbons

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 36

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

### **II.B. Exhaust Profile for Generator:**

[illegible]

Best Available Copy

Best Available Copy

# CALCULATION SHEET

PROJECT: RPP-WTP

JOB NO.: 24590

CALC NO.: 24590-WTP-HAC-50-00006

SHEET REV: A

SHEET NO.: 37

BY: J. Stan Hill

DATE: 6/17/03

SUBJECT: Emission Estimates for the Prevention of Significant Deterioration Permit Application, Rev. 1

## III. Emission data for Fire Water Pump:

### FIRE PUMP DRIVER EMISSION DATA

To complete an application for a Permit to Operate, the following data is provided.

6 Cylinders  
Four Cycle  
Lean Burn  
Turbocharged & Aftercooled  
Diesel Oil - Fuel  
No - Energy Recovery from Exhaust  
No - Emission Control Device

RPM	BHP <sup>(1)</sup>	FUEL	AIR/FUEL	GRAMS / HP / HR					% O <sub>2</sub>	EXHAUST		TIMING RETARD <sup>(2)</sup>
		GAL/HR (L/HR)	RATIO	HC <sup>(3)</sup>	NOx	CO	SO <sub>2</sub> <sup>(4)</sup>	PART. <sup>(4)</sup>		°F (°C)	CFM (m <sup>3</sup> /min)	
1760	300	14 (53)	31.8	0.07	5.1	0.22	0.14	0.07	11.3	829 (443)	1842 (46)	9.7
2100	340	16 (61)	35.4	0.15	4.5	0.45	0.14	0.09	12.5	744 (386)	2066 (59)	9.7
2350	350	17 (64)	37.6	0.20	4.2	0.62	0.15	0.11	13.0	735 (391)	2345 (66)	9.7

For specific RPM & BHP ratings, some of the above data may have been extrapolated from the best available test data.

1) Sulfur Dioxide based on 0.05% sulfur content in fuel (by weight).

2) Degrees of Timing RETARD for 'Beginning of Injection' based on comparison with pre-emission controlled engines.

3) HC is a measure of total hydrocarbons, including Non Methane Hydrocarbons (NMHC).

4) Part. is a measure of total particulates, including PM<sub>10</sub>.

5) Engines are rated at standard conditions of 29.61 in. (7521 mm) Hg barometer and 77°F (25°C) inlet air and raw water temperature.

Best Available Copy

## **Appendix C**

### **Treatment Technology Cost Analysis**

## Appendix C

### Treatment Technology Cost Analysis

Table C-1	Treatment Technology Cost Analysis – LAW Vitrification Selective Catalytic Reduction .....	C-1
Table C-2	Treatment Technology Cost Analysis – LAW Vitrification Selective Non-Catalytic Reduction .....	C-3
Table C-3	Treatment Technology Cost Analysis – LAW Vitrification Submerged Bed Scrubber .....	C-5
Table C-4	Treatment Technology Cost Analysis – LAW Vitrification Wet Caustic Scrubber .....	C-7
Table C-5	Treatment Technology Cost Analysis – HLW Vitrification Selective Catalytic Reduction .....	C-9
Table C-6	Treatment Technology Cost Analysis – HLW Vitrification Non-Selective Catalytic Reduction .....	C-11
Table C-7	Treatment Technology Cost Analysis – Submerged Bed Scrubber .....	C-13
Table C-8	Treatment Technology Cost Analysis – HLW Vitrification Wet Caustic Scrubber .....	C-15
Table C-9	Cost Effectiveness Calculation for the Diesel Particulate Filter Controls on the Diesel Generators .....	C-17
Table C-10	Treatment Technology Cost Analysis – Fabric Filter Pulse-Jet Baghouse for the Boilers: Total Capital Costs .....	C-18
Table C-11	Treatment Technology Cost Analysis – Fabric Filter Pulse-Jet Baghouse for the Boilers: Cost Effectiveness of Baghouse .....	C-20

**Table C-1 Treatment Technology Cost Analysis – LAW Vitrification Selective Catalytic Reduction**

Cost Item	Basis	Example Cost
<b>Direct Costs</b>		
Purchased Equipment Costs		
Equipment		\$798,000.00
Required Ancillary Equipment (\$10/cfm)		\$100,000.00
Instrumentation and Control	15 % of Equipment	\$119,700.00
Freight	5 % of Equipment	<u>\$39,900.00</u>
Subtotal Purchased Equipment Costs (PEC)		\$1,057,600.00
Direct Installation Costs		
Foundations & Supports	8 % of Subtotal PEC	\$84,608.00
Handling & Erection	14 % of Subtotal PEC	\$148,064.00
Electrical	4 % of Subtotal PEC	\$42,304.00
Piping and Duct Work	4 % of Subtotal PEC	\$42,304.00
Insulation for Piping & Equipment	4 % of Subtotal PEC	\$42,304.00
Painting	2 % of Subtotal PEC	<u>\$21,152.00</u>
Subtotal Installation Costs (IC)		\$380,736.00
Site Preparation	Equipment Specific	\$20,000.00
Building Costs	see cost factors below	equipment size
C5 Location per square foot	\$1,388/sf	166 sf
Subtotal - Building (per highest applicable cost area)	Equipment Specific	\$230,408.00
<b>Total Direct Cost</b>		<b>\$1,688,744.00</b>
<b>Indirect Costs (Installation)</b>		
Engineering	10 % of PEC	\$105,760.00
Construction and Field Expenses	5 % of PEC	\$52,880.00
Start-up	10 % of PEC	\$105,760.00
Performance Tests	1 % of PEC	\$10,576.00
Contingencies	15 % of PEC	\$158,640.00
<b>Total Indirect Costs</b>		<b>\$433,616.00</b>
<b>Total Capital Costs (TCC)</b>		<b>\$2,122,360.00</b>



**24590-WTP-RPT-ENV-01-007, Rev 1**  
**Prevention of Significant Deterioration Application for**  
**Hanford Tank Waste Treatment and Immobilization Plant**

**Table C-1 Treatment Technology Cost Analysis – LAW Vitrification Selective Catalytic Reduction**

Cost Item	Basis		Example Cost
<i>Direct Annual Costs</i>			
Utilities			
Electricity	\$0.08/kWhr		\$0.00
Steam	\$6.00/1000 lb		\$0.00
Water	\$0.25/1000 gal.		\$0.00
Materials/Chemicals	Process Specific		\$0.00
Operating Expenses			
Operator	\$20/Hr	52 hr	\$1,980.00
Supervisor	15 % of Operator		\$297.00
Secondary Waste Treatment & Disposal			
Maintenance			
Labor	\$17/Hr	72 hr/2 yr	\$612.00
Materials	Assume \$100,000/2 yr		\$50,000.00
<i>Indirect Annual Costs</i>			
Overhead	6 % of Labor Costs		\$1,733.40
Administrative	2 % of TCC		\$42,447.20
Insurance	1 % of TCC		\$21,223.60
<b>Total Annual Costs (TAC)</b>			<b>\$118,293.20</b>
Rate of Return on Capital Investment	10.00 %		
Service Life (years)	40		
Capital Recovery Factor	0.1023		
Annualized Capital Investment (ACI)			\$217,031.29
<b>Grand Total Annualized Costs</b>	<b>ACI + TAC</b>		<b>\$335,324.49</b>

Source: Modified from EPA Handbook *Control Technologies for Hazardous Air Pollutants* (June 1991).

**Table C-2 Treatment Technology Cost Analysis – LAW Vitrification Selective Non-Catalytic Reduction**

Cost Item	Basis	Example Cost
<b>Direct Costs</b>		
Purchased Equipment Costs		
Equipment		\$228,000.00
Required Ancillary Equipment (\$10/cfm)		\$100,000.00
Instrumentation and Control	15 % of Equipment	\$34,200.00
Freight	5 % of Equipment	<u>\$11,400.00</u>
Subtotal Purchased Equipment Costs (PEC)		\$373,600.00
Direct Installation Costs		
Foundations & Supports	8 % of Subtotal PEC	\$29,888.00
Handling & Erection	14 % of Subtotal PEC	\$52,304.00
Electrical	4 % of Subtotal PEC	\$14,944.00
Piping and Duct Work	4 % of Subtotal PEC	\$14,944.00
Insulation for Piping & Equipment	4 % of Subtotal PEC	\$14,944.00
Painting	2 % of Subtotal PEC	<u>\$7,472.00</u>
Subtotal Installation Costs (IC)		\$134,496.00
Site Preparation	Equipment Specific	\$20,000.00
Building Costs	see cost factors below	equipment size
C5 Location per square foot	\$1,388/sf	50
Subtotal - Building (per highest applicable cost area)	Equipment Specific	\$69,400.00
<b>Total Direct Cost</b>		<b>\$597,496.00</b>
<b>Indirect Costs (Installation)</b>		
Engineering	10 % of PEC	\$37,360.00
Construction and Field Expenses	5 % of PEC	\$18,680.00
Start-up	10 % of PEC	\$37,360.00
Performance Tests	1 % of PEC	\$3,736.00
Contingencies	15 % of PEC	\$56,040.00
<b>Total Indirect Costs</b>		<b>\$153,176.00</b>

**Table C-2 Treatment Technology Cost Analysis – LAW Vitrification Selective Non-Catalytic Reduction**

Cost Item	Basis		Example Cost
Total Capital Costs (TCC)			\$750,672.00
Direct Annual Costs			
Utilities			
Electricity	\$0.08/kWhr		\$500.00
Steam	\$6.00/1000 lb		\$0.00
Water	\$0.25/1000 gal.		\$10,000.00
Urea/Ammonia	Process Specific		\$10,074.00
Operating Expenses			
Operator	\$20/Hr	52 hr	\$1,980.00
Supervisor	15 % of Operator		\$297.00
Secondary Waste T&D			
Maintenance			
Labor	\$17/Hr	72 hr/2 yr	\$612.00
Materials			\$0.00
Indirect Annual Costs			
Overhead	6 % of Labor Costs		\$1,733.40
Administrative	2 % of TCC		\$15,013.44
Insurance	1 % of TCC		\$7,506.72
Total Annual Costs (TAC)			\$47,716.56
Rate of Return on Capital Investment	10.00 %		
Service Life (years)	40		
Capital Recovery Factor	0.1023		
Annualized Capital Investment (ACI)			\$76,763.28
Grand Total Annualized Costs	ACI + TAC	\$124,479.84	

Source: Modified from EPA Handbook *Control Technologies for Hazardous Air Pollutants* (June 1991).

**Table C-3 Treatment Technology Cost Analysis – LAW Vitrification Submerged Bed Scrubber**

Cost Item	Basis	Example Cost
<b>Direct Costs</b>		
Purchased Equipment Costs		
Equipment		\$3,192,000.00
Required Ancillary Equipment		\$0.00
Instrumentation and Control	15 % of Equipment	\$478,800.00
Freight	5 % of Equipment	<u>\$159,600.00</u>
Subtotal Purchased Equipment Costs (PEC)		\$3,830,400.00
Direct Installation Costs		
Foundations & Supports	8 % of Subtotal PEC	\$306,432.00
Handling & Erection	14 % of Subtotal PEC	\$536,256.00
Electrical	4 % of Subtotal PEC	\$153,216.00
Piping and Duct Work	4 % of Subtotal PEC	\$153,216.00
Insulation for Piping & Equipment	4 % of Subtotal PEC	\$153,216.00
Painting	2 % of Subtotal PEC	<u>\$76,608.00</u>
Subtotal Installation Costs (IC)		\$1,378,944.00
Site Preparation	Equipment Specific	\$20,000.00
Building Costs	see cost factors below equipment size	
C5 Location per square foot	\$1,388/sf 18 sf	\$24,984.00
Subtotal - Building (per highest applicable cost area)	Equipment Specific	\$24,984.00
<b>Total Direct Cost</b>		<b>\$5,254,328.00</b>
<b>Indirect Costs (Installation)</b>		
Engineering	10 % of PEC	\$383,040.00
Construction and Field Expenses	5 % of PEC	\$191,520.00
Start-up	10 % of PEC	\$383,040.00
Performance Tests	1 % of PEC	\$38,304.00
Contingencies	15 % of PEC	\$574,560.00
<b>Total Indirect Costs</b>		<b>\$1,570,464.00</b>

**Table C-3 Treatment Technology Cost Analysis – LAW Vitrification Submerged Bed Scrubber**

Cost Item	Basis		Example Cost
Total Capital Costs (TCC)			\$6,824,792.00
<i>Direct Annual Costs</i>			
Utilities			
Electricity	\$0.08/kWhr		\$0.00
Steam	\$6.00/1000 lb		\$0.00
Water	\$0.25/1000 gal.		\$5,000.00
Materials/Chemicals	Process Specific		\$25,000.00
Operating Expenses			
Operator	\$20/Hr	52 hrs/yr	\$1,040.00
Supervisor	15 % of Operator		\$156.00
Secondary Waste T&D	Process Specific		\$0.00
Maintenance			
Labor	\$17/Hr	24 hr/2 yr	\$204.00
Materials	100 % of Maintenance Labor		\$204.00
<i>Indirect Annual Costs</i>			
Overhead	6 % of Labor Costs		\$840.00
Administrative	2 % of TCC		\$136,495.84
Insurance	1 % of TCC		\$68,247.92
Total Annual Costs (TAC)			\$237,187.76
Rate of Return on Capital Investment	10.00 %		
Service Life (years)	40		
Capital Recovery Factor	0.1023		
Annualized Capital Investment (ACI)			\$697,899.23
Grand Total Annualized Costs	ACI + TAC		\$935,086.99

Source: Modified from EPA Handbook *Control Technologies for Hazardous Air Pollutants* (June 1991).

**Table C-4 Treatment Technology Cost Analysis – LAW Vitrification Wet Caustic Scrubber**

Cost Item	Basis	Example Cost
<b>Direct Costs</b>		
Purchased Equipment Costs		
Equipment		\$228,000.00
Required Ancillary Equipment		\$0.00
Instrumentation and Control	15 % of Equipment	\$34,200.00
Freight	5 % of Equipment	<u>\$11,400.00</u>
Subtotal Purchased Equipment Costs (PEC)		\$273,600.00
Direct Installation Costs		
Foundations & Supports	8 % of Subtotal PEC	\$21,888.00
Handling & Erection	14 % of Subtotal PEC	\$38,304.00
Electrical	4 % of Subtotal PEC	\$10,944.00
Piping and Duct Work	4 % of Subtotal PEC	\$10,944.00
Insulation for Piping & Equipment	4 % of Subtotal PEC	\$10,944.00
Painting	2 % of Subtotal PEC	<u>\$5,472.00</u>
Subtotal Installation Costs (IC)		\$98,496.00
Site Preparation	Equipment Specific	\$20,000.00
Building Costs	see cost factors below	equipment size
C5 Location per square foot	\$1,388/sf	18 sf
Subtotal - Building (per highest applicable cost area)	Equipment Specific	\$24,984.00
<b>Total Direct Cost</b>		<b>\$417,080.00</b>
<b>Indirect Costs (Installation)</b>		
Engineering	10 % of PEC	\$27,360.00
Construction and Field Expenses	5 % of PEC	\$13,680.00
Start-up	10 % of PEC	\$27,360.00
Performance Tests	1 % of PEC	\$2,736.00
Contingencies	15 % of PEC	\$41,040.00
<b>Total Indirect Costs</b>		<b>\$112,176.00</b>

**Table C-4 Treatment Technology Cost Analysis – LAW Vitrification Wet Caustic Scrubber**

Cost Item	Basis		Example Cost
Total Capital Costs (TCC)			\$529,256.00
<i>Direct Annual Costs</i>			
Utilities			
Electricity	\$0.08/kWhr		\$0.00
Steam	\$6.00/1000 lb		\$0.00
Water	\$0.25/1000 gal.		\$5,000.00
Materials/Chemicals	Process Specific		\$25,000.00
Operating Expenses			
Operator	\$20/Hr	52 hrs.	\$1,040.00
Supervisor	15 % of Operator		\$156.00
Secondary Waste T&D	Process Specific		\$0.00
Maintenance			
Labor	\$17/Hr	24 hr/2 yr	\$204.00
Materials	100 % of Maintenance Labor		\$204.00
<i>Indirect Annual Costs</i>			
Overhead	6 % of Labor Costs		\$840.00
Administrative	2 % of TCC		\$10,585.12
Insurance	1 % of TCC		\$5,292.56
Total Annual Costs (TAC)			\$48,321.68
Rate of Return on Capital Investment	10.00%		
Service Life (years)	40		
Capital Recovery Factor	0.1023		
Annualized Capital Investment (ACI)			\$54,121.41
Grand Total Annualized Costs	ACI + TAC		\$102,443.09

Source: Modified from EPA Handbook *Control Technologies for Hazardous Air Pollutants* (June 1991).

**Table C-5 Treatment Technology Cost Analysis – HLW Vitrification Selective Catalytic Reduction**

Cost Item	Basis	Example Cost
<b>Direct Costs</b>		
Purchased Equipment Costs		
Equipment		\$193,200.00
Required Ancillary Equipment (\$10/cfm)		\$23,000.00
Instrumentation and Control	15 % of Equipment	\$28,980.00
Freight	5 % of Equipment	<u>\$9,660.00</u>
Subtotal Purchased Equipment Costs (PEC)		\$254,840.00
Direct Installation Costs		
Foundations & Supports	8 % of Subtotal PEC	\$20,387.20
Handling & Erection	14 % of Subtotal PEC	\$35,677.60
Electrical	4 % of Subtotal PEC	\$10,193.60
Piping and Duct Work	4 % of Subtotal PEC	\$10,193.60
Insulation for Piping & Equipment	4 % of Subtotal PEC	\$10,193.60
Painting	2 % of Subtotal PEC	<u>\$5,096.80</u>
Subtotal Installation Costs (IC)		\$91,742.40
Site Preparation	Equipment Specific	\$20,000.00
Building Costs	see cost factors below	equipment size
C5 Location per square foot	\$1,388/sf	66 sf
Subtotal - Building (per highest applicable cost area)	Equipment Specific	\$91,608.00
<b>Total Direct Cost</b>		<b>\$458,190.40</b>
<b>Indirect Costs (Installation)</b>		
Engineering	10 % of PEC	\$25,484.00
Construction and Field Expenses	5 % of PEC	\$12,742.00
Start-up	10 % of PEC	\$25,484.00
Performance Tests	1 % of PEC	\$2,548.40
Contingencies	15 % of PEC	\$38,226.00
<b>Total Indirect Costs</b>		<b>\$104,484.40</b>



**Table C-5 Treatment Technology Cost Analysis – HLW Vitrification Selective Catalytic Reduction**

Cost Item	Basis		Example Cost
Total Capital Costs (TCC)			\$562,674.80
Direct Annual Costs			
Utilities			
Electricity	\$0.08/kWhr		\$0.00
Steam	\$6.00/1000 lb		\$0.00
Water	\$0.25/1000 gal.		\$0.00
Materials/Chemicals	Process Specific		\$0.00
Operating Expenses			
Operator	\$20/Hr	52 hr	\$1,980.00
Supervisor	15% of Operator		\$297.00
Secondary Waste T&D			
Maintenance			
Labor	\$17/Hr	72 hr/2 yr	\$612.00
Materials	Assume \$100,000/2 yr		\$50,000.00
Indirect Annual Costs			
Overhead	6 % of Labor Costs		\$1,733.40
Administrative	2 % of TCC		\$11,253.50
Insurance	1 % of TCC		\$5,626.75
Total Annual Costs (TAC)			\$71,502.64
Rate of Return on Capital Investment	10.00 %		
Service Life (years)	40		
Capital Recovery Factor	0.1023		
Annualized Capital Investment (ACI)			\$57,538.80
Grand Total Annualized Costs	ACI + TAC	\$129,041.44	

Source: Modified from EPA Handbook *Control Technologies for Hazardous Air Pollutants* (June 1991).

**Table C-6 Treatment Technology Cost Analysis – HLW Vitrification Non-Selective Catalytic Reduction**

Cost Item	Basis	Example Cost
<b>Direct Costs</b>		
Purchased Equipment Costs		
Equipment		\$55,200.00
Required Ancillary Equipment (\$10/cfm)		\$23,000.00
Instrumentation and Control	15 % of Equipment	\$8,280.00
Freight	5 % of Equipment	<u>\$2,760.00</u>
Subtotal Purchased Equipment Costs (PEC)		\$89,240.00
Direct Installation Costs		
Foundations & Supports	8 % of Subtotal PEC	\$7,139.20
Handling & Erection	14 % of Subtotal PEC	\$12,493.60
Electrical	4 % of Subtotal PEC	\$3,569.60
Piping and Duct Work	4 % of Subtotal PEC	\$3,569.60
Insulation for Piping & Equipment	4 % of Subtotal PEC	\$3,569.60
Painting	2 % of Subtotal PEC	<u>\$1,784.80</u>
Subtotal Installation Costs (IC)		\$32,126.40
Site Preparation	Equipment Specific	\$20,000.00
Building Costs	see cost factors below equipment size	
C5 Location per square foot	\$1,388/sf	50 \$69,400.00
Subtotal - Building (per highest applicable cost area)	Equipment Specific	\$69,400.00
<b>Total Direct Cost</b>		<b>\$210,766.40</b>
<b>Indirect Costs (Installation)</b>		
Engineering	10 % of PEC	\$8,924.00
Construction and Field Expenses	5 % of PEC	\$4,462.00
Start-up	10 % of PEC	\$8,924.00
Performance Tests	1 % of PEC	\$892.40
Contingencies	15 % of PEC	\$13,386.00
<b>Total Indirect Costs</b>		<b>\$36,588.40</b>

**Table C-6 Treatment Technology Cost Analysis – HLW Vitrification Non-Selective Catalytic Reduction**

Cost Item	Basis		Example Cost
Total Capital Costs (TCC)			\$247,354.80
<i>Direct Annual Costs</i>			
Utilities			
Electricity	\$0.08/kWhr		\$500.00
Steam	\$6.00/1000 lb		\$0.00
Water	\$0.25/1000 gal.		\$10,000.00
Urea/Ammonia	Process Specific		\$10,074.00
Operating Expenses			
Operator	\$20/Hr	52 hr	\$1,980.00
Supervisor	15 % of Operator		\$297.00
Secondary Waste T&D			
Maintenance			
Labor	\$17/Hr	72 hr/2 yr	\$612.00
Materials			\$0.00
<i>Indirect Annual Costs</i>			
Overhead	6 % of Labor Costs		\$1,733.40
Administrative	2 % of TCC		\$4,947.10
Insurance	1 % of TCC		\$2,473.55
Total Annual Costs (TAC)			\$32,617.04
Rate of Return on Capital Investment	10.00 %		
Service Life (years)	40		
Capital Recovery Factor	0.1023		
Annualized Capital Investment (ACI)			\$25,294.36
Grand Total Annualized Costs	ACI + TAC	\$57,911.40	

Source: Modified from EPA Handbook *Control Technologies for Hazardous Air Pollutants* (June 1991).

**Table C-7 Treatment Technology Cost Analysis – Submerged Bed Scrubber**

Cost Item	Basis	Example Cost
<b>Direct Costs</b>		
Purchased Equipment Costs		
Equipment		\$772,800.00
Required Ancillary Equipment		\$0.00
Instrumentation and Control	15 % of Equipment	\$115,920.00
Freight	5 % of Equipment	<u>\$38,640.00</u>
Subtotal Purchased Equipment Costs (PEC)		\$927,360.00
Direct Installation Costs		
Foundations & Supports	8 % of Subtotal PEC	\$74,188.80
Handling & Erection	14 % of Subtotal PEC	\$129,830.40
Electrical	4 % of Subtotal PEC	\$37,094.40
Piping and Duct Work	4 % of Subtotal PEC	\$37,094.40
Insulation for Piping & Equipment	4 % of Subtotal PEC	\$37,094.40
Painting	2 % of Subtotal PEC	<u>\$18,547.20</u>
Subtotal Installation Costs (IC)		\$333,849.60
Site Preparation	Equipment Specific	\$20,000.00
Building Costs	see cost factors below	equipment size
C5 Location per square foot	\$1,388/sf	2 sf
		\$2,776.00
Subtotal - Building (per highest applicable cost area)	Equipment Specific	\$2,776.00
<b>Total Direct Cost</b>		<b>\$1,283,985.60</b>
<b>Indirect Costs (Installation)</b>		
Engineering	10 % of PEC	\$92,736.00
Construction and Field Expenses	5 % of PEC	\$46,368.00
Start-up	10 % of PEC	\$92,736.00
Performance Tests	1 % of PEC	\$9,273.60
Contingencies	15 % of PEC	\$139,104.00
<b>Total Indirect Costs</b>		<b>\$380,217.60</b>

**Table C-7 Treatment Technology Cost Analysis – Submerged Bed Scrubber**

Cost Item	Basis		Example Cost
Total Capital Costs (TCC)			\$1,664,203.20
<i>Direct Annual Costs</i>			
Utilities			
Electricity	\$0.08/kWhr		\$0.00
Steam	\$6.00/1000 lb		\$0.00
Water	\$0.25/1000 gal.		\$500.00
Materials/Chemicals	Process Specific		\$2,500.00
Operating Expenses			
Operator	\$20/Hr	52 hrs/yr	\$1,040.00
Supervisor	15 % of Operator		\$156.00
Secondary Waste T&D	Process Specific		\$0.00
Maintenance			
Labor	\$17/Hr	24 hr/2 yr	\$204.00
Materials	100% of Maintenance Labor		\$204.00
<i>Indirect Annual Costs</i>			
Overhead	6 % of Labor Costs		\$840.00
Administrative	2 % of TCC		\$33,284.06
Insurance	1 % of TCC		\$16,642.03
Total Annual Costs (TAC)			\$55,370.10
Rate of Return on Capital Investment	10.00 %		
Service Life (years)	40		
Capital Recovery Factor	0.1023		
Annualized Capital Investment (ACI)			\$170,180.44
Grand Total Annualized Costs	ACI + TAC		\$225,550.54

Source: Modified from EPA Handbook *Control Technologies for Hazardous Air Pollutants* (June 1991).

**Table C-8 Treatment Technology Cost Analysis – HLW Vitrification Wet Caustic Scrubber**

Cost Item	Basis	Example Cost
<b>Direct Costs</b>		
Purchased Equipment Costs		
Equipment		\$55,200.00
Required Ancillary Equipment		\$0.00
Instrumentation and Control	15 % of Equipment	\$8,280.00
Freight	5 % of Equipment	<u>\$2,760.00</u>
Subtotal Purchased Equipment Costs (PEC)		\$66,240.00
Direct Installation Costs		
Foundations & Supports	8 % of Subtotal PEC	\$5,299.20
Handling & Erection	14 % of Subtotal PEC	\$9,273.60
Electrical	4 % of Subtotal PEC	\$2,649.60
Piping and Duct Work	4 % of Subtotal PEC	\$2,649.60
Insulation for Piping & Equipment	4 % of Subtotal PEC	\$2,649.60
Painting	2 % of Subtotal PEC	<u>\$1,324.80</u>
Subtotal Installation Costs (IC)		\$23,846.40
Site Preparation	Equipment Specific	\$20,000.00
Building Costs	see cost factors below	equipment size
C5 Location per square foot	\$1,388/sf	2 sf
Subtotal - Building (per highest applicable cost area)	Equipment Specific	\$2,776.00
<b>Total Direct Cost</b>		<b>\$112,862.40</b>
<b>Indirect Costs (Installation)</b>		
Engineering	10 % of PEC	\$6,624.00
Construction and Field Expenses	5 % of PEC	\$3,312.00
Start-up	10 % of PEC	\$6,624.00
Performance Tests	1 % of PEC	\$662.40
Contingencies	15 % of PEC	\$9,936.00
<b>Total Indirect Costs</b>		<b>\$27,158.40</b>

**24590-WTP-RPT-ENV-01-007, Rev 1**  
**Prevention of Significant Deterioration Application for**  
**Hanford Tank Waste Treatment and Immobilization Plant**

**Table C-8 Treatment Technology Cost Analysis – HLW Vitrification Wet Caustic Scrubber**

Cost Item	Basis		Example Cost
Total Capital Costs (TCC)			\$140,020.80
<i>Direct Annual Costs</i>			
Utilities			
Electricity	\$0.08/kWhr		\$0.00
Steam	\$6.00/1000 lb		\$0.00
Water	\$0.25/1000 gal.		\$500.00
Materials/Chemicals	Process Specific		\$2,500.00
Operating Expenses			
Operator	\$20/Hr	52 hrs	\$1,040.00
Supervisor	15 % of Operator		\$156.00
Secondary Waste T&D	Process Specific		\$0.00
Maintenance			
Labor	\$17/Hr	24 hr/2 yr	\$204.00
Materials	100% of Maintenance Labor		\$204.00
<i>Indirect Annual Costs</i>			
Overhead	6 % of Labor Costs		\$840.00
Administrative	2 % of TCC		\$2,800.42
Insurance	1 % of TCC		\$1,400.21
Total Annual Costs (TAC)			\$9,644.62
Rate of Return on Capital Investment	10.00 %		
Service Life (years)	40		
Capital Recovery Factor	0.1023		
Annualized Capital Investment (ACI)			\$14,318.45
Grand Total Annualized Costs	ACI + TAC		\$23,963.07

Source: Modified from EPA Handbook *Control Technologies for Hazardous Air Pollutants* (June 1991).

**Table C-9 Cost Effectiveness Calculation for the Diesel Particulate Filter Controls on the Diesel Generators**

Annual Cost Element	Unit/Calculation	Calculated Costs	Total Annualized Cost
Operating labor expense	\$20/hr x 12 hr/yr	\$240	
	15 % of labor	\$36	
Maintenance labor	\$17/hr x 36 hr/yr	\$612	
Maintenance material			
Overhead (60% of labor cost)	0.6 x \$888	\$533	
Administrative (2% of TCC)	0.02 x \$450,300	\$9,006	
Insurance (1% of TCC)	0.01 x \$450,300	\$4,503	
<b>Total Annual Cost (TAC)</b>		<b>\$14,930</b>	<b>\$14,930</b>
Capital recovery factor (CRC) (7%, 5 years) x TCC	0.142377502727 x \$450,300	\$64,112	<b>\$64,112</b>
<b>Annualized Capital Investment (ACI)</b>	CRC= $i(1+i)^n / [(1+i)^n - 1]$ i= 0.07, n=5		
<b>Grand Total Annualized Cost (TAC + ACI)</b>			<b>\$79,042</b>
<b>Total Annualized Cost (TAC + ACI)/Annual US Ton of NOx removed</b>	1.0 US tons per year x 0.85 ≈  0.85 US tons per year PM removed	<b>\$79,042/0.85 US tons per year</b>	<b>\$92,990/US ton of PM removed</b>



**Table C-10 Treatment Technology Cost Analysis – Fabric Filter Pulse-Jet Baghouse for the Boilers: Total Capital Costs**

Cost Items	Factor	Estimated Cost
<b>Direct Capital Costs</b>		
<i><b>Purchased Equipment Costs</b></i>		
Fabric Filter (EC) + bags + auxiliary equipment	Vendor Quote	\$881,723
Material Handling Equipment	Vendor Quote	\$35,079
Main fan system and air compressor(s)	Vendor Quote	\$193,930
Bleed Cooler, silo, and vent system	Vendor Quote	\$165,000
Vendor field assistance services	Vendor Quote	\$17,600
<i><b>Subtotal Purchased Equipment Costs (PEC)</b></i>		<b>\$1,293,332</b>
<i><b>Direct Installation Costs</b></i>		
Foundations and Supports	4 % of Subtotal PEC	\$51,733
Handling and Erection	50 % of Subtotal PEC	\$646,666
Electrical	8 % of Subtotal PEC	\$103,467
Piping and Duct Work	1 % of Subtotal PEC	\$12,933
Insulation for Piping and Equipment	7 % of Subtotal PEC	\$90,533
Painting	4 % of Subtotal PEC	\$51,733
<i><b>Subtotal Installation Costs (IC)</b></i>		<b>\$957,066</b>
<i><b>Site Preparation</b></i>	Equipment Specific	-
<i><b>Building Costs</b></i>	Equipment Specific	-
	Cost Factor - \$/square foot	
	Equipment Size – 35' x 35'	
<b>Total Direct Capital Costs</b>		<b>\$2,250,398</b>
<b>Indirect Capital Costs (Installation)</b>		
Engineering	10 % of PEC	\$129,333
Construction and Field Expenses	20 % of PEC	\$64,667
Contractor Fees	10 % of PEC	\$129,333
Start-up	1 % of PEC	\$12,933
Performance test	1 % of PEC	\$194,000

**Table C-10 Treatment Technology Cost Analysis – Fabric Filter Pulse-Jet Baghouse for the Boilers: Total Capital Costs**

Cost Items	Factor	Estimated Cost
Contingencies	3 % of PEC	\$38,800
<b>Total Indirect Capital Costs</b>		<b>\$569,066</b>
<b>Total Capital Costs (TCC)</b>		<b>\$2,819,464</b>

Capital equipment cost quote from Willard Goss, Beaumont Environmental Systems, Proposal Number 106-1, April 9, 2003

Annualized Costs: EPA Air Pollution Control Cost Manual, Sixth Edition, EPA-452-02-001, USEPA, OAQPS, RTP, NC, January 2002.

**Table C-11 Treatment Technology Cost Analysis – Fabric Filter Pulse-Jet Baghouse for the Boilers: Cost Effectiveness of Baghouse**

Cost Items	Factor	Estimated Cost
<b>Direct Annual Cost</b>		
<i><b>Operating Expenses</b></i>		
Operator	2 hr/shift/day x 3 shifts/day x 360days/yr x \$17.26/hr	\$37,282
Supervisor	15 % of Operator	\$5,592
Operating Materials/Chemical	None expected	
<i><b>Maintenance</b></i>		
Labor	1 hr/shift/day x 3 shifts/day x 360days/yr x \$17.74/hr	\$18,641
Materials	100 % of MAintenance Labor	\$18,641
<i><b>Replacement Parts/Filter Bags</b></i>	$\{[3943 + (26,791 \times 1.08)] \times (144,166/50,000)\} \times 0.5531$	\$18,184
<i><b>Utilities</b></i>		
Electricity	$0.000181 \times 144166/50000 \times 50000 \text{ acfm} \times 10.3 \text{ inH}_2\text{O} \times 8640\text{hr/yr} \times \$0.0671/\text{kWh}$	\$155,817
Compressed Air	$2 \text{ scfm}/1000 \text{ acfm} \times 144,166 \text{ acfm} \times \$0.25/1000 \text{ scf} \times 60 \text{ min/hr} \times 8640 \text{ h/yr}$	\$37,368
<i><b>Solid Waste Disposal</b></i>	18.7 tpy at \$150/ton	\$2,805
<b>Total Direct Annual Costs (DAC)</b>		<b>\$294,330</b>
<b>Indirect Annual Costs</b>		
Overhead	60 % of Labor Costs	\$48,093
Administrative Charges	2 % of TCC	\$56,389
Property Tax	1 % of TCC	\$28,195
Insurance	1 % of TCC	\$28,195
Capital Recovery	$0.0944 \times (\text{TCC} - \{[3943 + (26,791 \times 1.08)] \times (144,166/50,000)\})$	\$257,189
<b>Total Indirect Annual Costs (IAC)</b>		<b>\$418,061</b>
Rate of Return on Capital Investment	7.00 %	
Service Life (years)	20	

**Table C-11 Treatment Technology Cost Analysis – Fabric Filter Pulse-Jet Baghouse for the Boilers: Cost Effectiveness of Baghouse**

Cost Items	Factor	Estimated Cost
Capital Recovery Factor (CRF)	0.944	
<b>Grand Total Annualized Costs (TAC)</b>	<b>TAC=DAC+IAC</b>	<b>\$712,391</b>
<b>Cost Effectiveness of Baghouse</b>		
US \$ per US ton per year of particulate matter removed		<b>\$38,096</b>

Source: EPA Air Pollution Control Cost Manual, Sixth Edition, EPA-452-02-001, USEPA, OAQPS, RTP, NC, January 2002